Eastern Economy Edition

Second Edition

POWER PLANT INSTRUMENTATION

K. Krishnaswamy
M. Ponni Bala

PHI

Power Plant Instrumentation

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Second Edition

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POWER PLANT INSTRUMENTATION, Second Edition
K. Krishnaswamy and M. Ponni Bala

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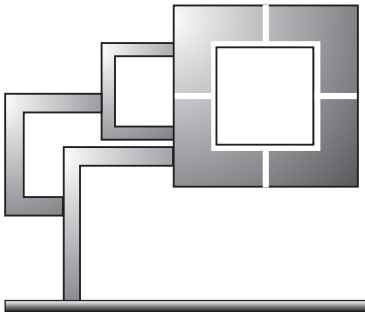

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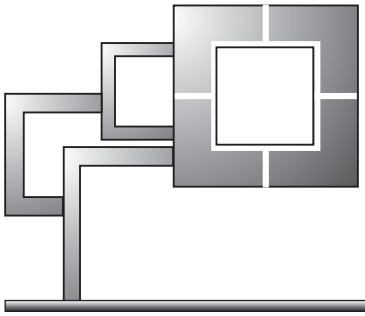

Foreword

Instrumentation plays a vital role in thermal power plants, facilitating the production of reliable and quality power as economically as possible. Hence a course on 'Power Plant Instrumentation' invariably finds a place in the curriculum of Electronics and Instrumentation Engineering, and that of Electrical and Electronics Engineering branches in all technical universities. The faculty and students find it difficult to locate a textbook covering the entire syllabus. Prof. K. Krishnaswamy, with his vast professional experience in thermal power plants and in academic subjects, has brought out the various aspects of Power Plant Instrumentation in a compact book with numerous illustrations. The book has been divided into five chapters and deals with the subject in depth. The first chapter provides an overview of power generation covering the various conventional and non-conventional energy sources. Chapters two and three cover the instrumentation and controls of water-steam and air-fuel-flue gas circuits of boilers. The fourth chapter deals with the power plant management system, consisting of combustion and efficiency calculations, maintenance and safety aspects, and Supervisory Control and Data Acquisition (SCADA) system. The fifth chapter covers mainly the aspects of turbine monitoring and control. Ms. M. Ponni Bala, Assistant Professor in the Department of Electronics and Instrumentation Engineering, who has taught the subject for many years has co-authored the book. At the end of each chapter, a number of worked out problems have been given, and in addition a set of thought-provoking exercises are included. Therefore, the book *Power Plant Instrumentation* will be of immense value to both the faculty and students. It is also intended to serve as a reference book for professionals in thermal power plants. It really gives me immense pleasure to introduce to the students, the faculty and the power plant professionals, the outcome of the excellent and dedicated efforts of our senior professor along with an assistant professor of our college.

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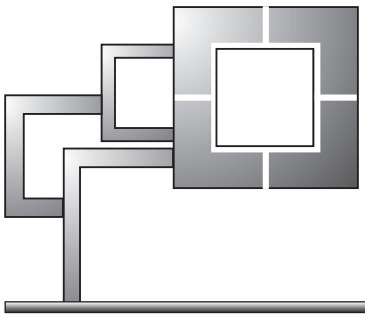
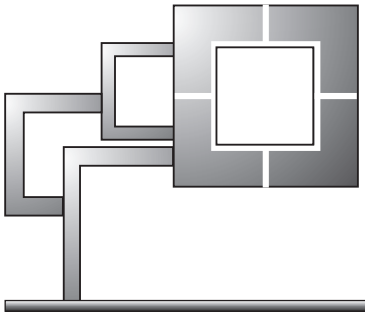


Preface

The first edition of this book was published in the beginning of the year 2011. The book found overwhelming response from both students and teaching faculty of engineering courses. There is a popular demand from users for adding a chaper on 'Nuclear Power Plant Instrumentation'. The authors also felt the demand as genuine and added the additional chapter covering mainly the fundamentals of measurements involved in the nuclear power plants, reactor power control and radiation safety aspects. The importance of radiation safety is emphasized greatly by giving brief summary of the four major accidents occurred all over the world in nuclar power plants.

We sincerely hope that this new edition confirms the trust which our readers have on us. Critical suggestions are always welcome for further improvement of this book.

K. Krishnaswamy
M. Ponni Bala



Preface to the First Edition

When I joined as Graduate Engineer in Rourkela Steel Plant, Hindustan Steel Limited [Now, Steel Authority of India Limited (SAIL)] immediately after completing my Master's degree from Indian Institute of Technology Madras in 1971, I was posted in the captive power plant. The plant was generating 128 MW with five boilers and five turbo alternators of 25 MW capacity each and a back pressure turbine of 3 MW capacity. The boilers used multi-fuels, namely coal, blast furnace gas and furnace oil. It was really a training ground for me to learn the complete Power Plant Instrumentation. I searched for a good textbook that could provide enough information on Power Plant Instrumentation. I could get some information from the handbook, *Process Control System* by B.G. Liptak, but that was really not sufficient. However, *Power Plant Engineering* by Frederic T. Morse helped me to learn more about the mechanical equipment in power plants, but very little about instrumentation. When Rourkela Steel Plant went in for expansion, one more captive power plant of 120 MW capacity, with two boilers and two alternators of 60 MW each, was commissioned. I was involved in the project from the beginning and got a long exposure in erection, commissioning, testing and maintenance of the Power Plant Instrumentation system. During that time, I found a book titled *The Control of Boilers* by Sam G. Dukelow which covered most of the topics on boiler controls. When I took up the task of training the instrument technicians for the plant, I found it extremely difficult because of the absence of a standard textbook that provided complete details on Power Plant Instrumentation. I then collected a lot of material from the instruction books of instruments' suppliers and combined it with the material from the above-mentioned books in order to provide training materials to the technicians. This exercise prompted me to think of writing a book on Power Plant Instrumentation. It did not materialize then as I was busy with other activities in the steel plant.

Later when I joined an academic institution I found that almost all technical universities in India offered 'Power Plant Instrumentation' as a course for Electronics and Instrumentation, and Electrical and Electronics Engineering branches. To my utter surprise I came to know that still a comprehensive textbook was not available on this subject. This fact rekindled my interest to

author a textbook on the topic. Because of my little experience in the academic field, I decided to associate Ms. M. Ponni Bala as a co-author, who has a vast experience in teaching the subject for many years. When I started teaching the same subject, it gave me an opportunity to share my experiences on power plants with the students. The positive response of the students and the encouragement given by the management of the Kongu Vellalar Institute of Technology Trust, Principal and the faculty, has finally made me realize the task of bringing out a comprehensive textbook on Power Plant Instrumentation.

The main purpose of writing this book is to first introduce the various sources of electrical energy and then to concentrate on steam power that is used to generate electricity. The automation and controls involved in water-steam circuit and fuel-air-flue gases circuit are covered next. Economy, reliability and safety aspects are then analysed and the turbine controls are introduced as well.

This book should be of great value to the students of Electronics and Instrumentation Engineering and Electrical and Electronics Engineering courses. When used as a textbook, it is desirable to cover the entire book, rather than concentrating on a few sections only. It will not only prove to be informative to young mechanical and chemical engineers as they enter the field of power generation, but also prove to be interesting to those already practising and wishing to broaden their insights into controls and automation of boilers and turbines, something they might have missed during their college days. Senior executives and managers should also find this material useful. The book will help them manage the operation of thermal power plants in a more economical, reliable and safe manner.

I have mixed some of the ideas from already available printed material, my field experience gained while working in two captive power plants and the teaching experience of Ms. Ponni Bala, to bring out this book. Errors of typography, calculations or statements if any in this book may be reported to the authors.

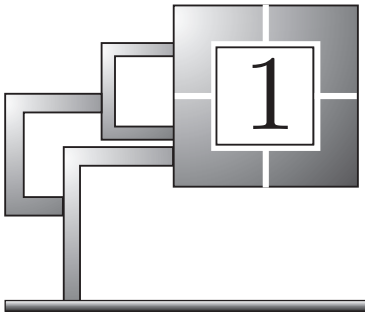
K. Krishnaswamy

Acknowledgements

A number of persons have very kindly assisted us in completing this book. Their help and technical knowledge have contributed mightily to the quality of this work. We gratefully acknowledge all their efforts. This book would never have been written without the active support and assistance of the Management of the Kongu Vellalar Institute of Technology Trust, Perundurai and patronage of Prof. S. Kuppuswami, Principal, Kongu Engineering College, Perundurai. We are indebted to the members of faculty of the Department of Electronics and Instrumentation Engineering for their comments, suggestions and moral support. We express our sincere thanks to Ms. L. Kalpana, data entry operator for her excellent assistance in electronic processing of the manuscript.

K. Krishnaswamy

M. Ponni Bala



Overview of Power Generation

1.1 INTRODUCTION

Energy can neither be created nor destroyed and this is the law of nature. Energy available in one form can be converted into energy of another form. For example, heat energy can be converted into mechanical energy which in turn can be converted into electrical energy. Energy is available in different forms. Energy sources can be broadly divided into two categories, namely the conventional and the non-conventional energy sources. Energy available in one form, if it cannot be used in the same form, can be transformed into another convenient form.

1.2 VARIOUS SOURCES OF ELECTRICAL ENERGY

Electrical energy is predominating over others due to its easy transportation. It is also considered as the most clean form of energy. Electrical energy can be produced or rather converted from other forms of energy in many ways. The conventional ways of generating electrical energy are through hydel, nuclear, thermal or gaseous routes. The non-conventional means are solar, tidal, wind, geothermal, fuel cells, biogas and magnetohydrodynamic (MHD). In all these cases, the energy is first converted into electrical form which in turn, can be utilized in the form of light, heat and other rotation or mechanical energy. Sir Thomas Alva Edison was the man behind the revolution of electricity. An electrical power station of small size was put up by him in 1880s which became the foundation for super power stations being put up nowadays.

Though various sources are available, the use of thermal energy for generating electrical energy has occupied the prime position in the modern world. The close competitor is the hydel source followed way behind by nuclear source. Though the aim of this textbook is to cover the measurements and controls practised in steam thermal power plant, the fundamentals of all sources of energy will be discussed first to the benefit of the readers.

1.3 NON-CONVENTIONAL ENERGY SOURCES

The non-conventional energy sources are often referred to as 'renewable' energy sources. It is presumed that such sources are available free of cost. They are pollution-free and available in plenty, but the cost of harnessing the non-conventional energy sources is considered to be very high. The transportation of such sources to place of production, development for adopting them for power generation and the seasonal availability are some of the factors to be addressed. As the fossil-fuel sources are getting depleted day by day, research and development works are being carried out vigorously throughout the world for alternate sources. It is certain that the non-conventional energy sources will play an important role in the future energy scenario.

The installation of non-conventional power stations will offset the need for setting up a coal-based thermal power station which is the dominant conventional source of electrical supply and hence reduce emission of greenhouse gases (GHGs), responsible for global warming and other pollutants. Due to construction of high hydroelectric dams, productive land and forests get destroyed and villages get submerged in water. This causes numerous environmental and social issues. The non-conventional ones create no such issues and hence are perfectly 'people-friendly'.

Large-scale use of the non-conventional sources can produce substantial reductions in green-house gas emissions, particularly carbon dioxide. The major generation capacities are largely coal-based and produce high quantity of carbon dioxide and other harmful gases. If the untapped non-conventional energy potential is realized, carbon dioxide and other toxic gas emission can be lowered significantly and thereby saving our environment. Therefore, every kilowatt of non-conventional energy produced, has to be seen from this angle and as a small but major step towards mitigation of carbon dioxide emission and subsequently combat climate change.

To understand the long-term social benefits of the non-conventional energy sources, the evil effects of climate change are briefly examined below.

1. Rising levels of greenhouse gases are expected to cause climate change. By absorbing infrared radiation, these gases control the flow of natural energy through the climate system. The climate has to adjust to the thickening blanket of greenhouse gases. Climate models predict that the global temperature shall rise by about 1–3.5 degree Celsius by the year 2100. It may be noted that this projected change is larger than any other climate change experienced over the last 10,000 years.
2. The mean sea level is expected to rise 15 to 95 cm due to melting of ice by the year 2100, causing flooding of low-lying areas and causing other damages. Forests, deserts and other unmanaged ecosystems would face new climatic stresses. Human society shall face new risks and pressures. Food security is likely to be affected and some regions are likely to experience food shortages and hunger. Water resources shall be affected as precipitation and evaporation pattern change around the world. Sea level change and extreme weather events could damage physical infrastructure. SOx and NOx emissions from coal and oil-fired power stations produce cloud of microscopic particles that reflect sunlight back into space and cause acid rain.

1.3.1 Wind Power

Out of all the non-conventional energy sources, wind energy leads the scenario. It is available in plenty and is also pollution-free. But the availability is seasonal and location-oriented. The wind

field has to be selected in such a way that the minimum required wind velocity is available for a long period in a year. Large-scale power generation was considered impossible earlier due to uncertainties of wind. Nowadays it has become a practice to spot out the locations where the minimum wind velocity is available through the most part of a year and install number of windmills in such locations. This way, the processes of collection of power and transmission to the grid become economical. Energy crisis in the world is compelling the development of wind power as an alternative to fuel-fired power generation. The wind power tapped now is forming a significant portion of the energy demand.

Windmills convert the wind energy or wind velocity to mechanical energy which in turn, rotates the rotor of the electrical generator to produce electric power. The power thus developed is proportional to the cube of wind's velocity and the swept area of the blades attached to the shaft. The power developed is governed by the formula assuming the density of air as 1.2 kg/m^3,

$$P_D = 13.14 \times 10^{-6}\, AV^3 \text{ kW}$$

where

P_D = Power developed by the windmill in kW
A = Swept area in square metre (m^2)
V = Wind velocity in km/hr

Typical windmills are capable of producing around 50 kW power and wind farms with a number of windmills may account for power generation of around 2 MW per farm. Wind turbines are located at a height of 60 to 80 metres and have two or three-bladed propeller rotating around a horizontal axis.

1.3.2 Solar Power

The sun is a powerful source of heat energy. Even if a portion of energy is utilized to produce electrical energy, the mankind on earth will have abundant energy. Solar power gives confidence for a brighter and cleaner future. Statistics says that 0.1% of solar energy converted at an efficiency of 10% would be 4 times the world's generating capacity of about 3000 GW. With improvements in technology for harnessing solar energy, it is expected that in future, the majority of the energy needs will be met by solar energy globally. Power from the sun is clean, silent, limitless and free. Another key advantage is its distributed nature. Power can be produced wherever needed avoiding transmission losses. Photovoltaic conversion and thermal conversion are the two basic means of generating electricity from solar energy.

Photovoltaic (PV) conversion

The photovoltaic technology has numerous environmental benefits. As it quietly generates electricity from light, it produces no air pollution or hazardous waste. The photovoltaic devices convert light from the sun into usable form of electrical energy. The system mainly consists of photovoltaic modules (Modules use multicrystalline silicon photovoltaic cells) to produce D.C power first. The modules are covered with outer glass layer to enhance the optical performance of the unit and therefore the operational performance of the cells. Inverters are used to convert the DC energy into AC energy for further use. The inverters shall be outdoor installation type with suitable protective measures incorporated. The rated capacity of the typical plants range from a few kW to 1MW.

Thermal conversion

Unlike photovoltaic conversion which is using light energy, the thermal conversion process uses the heat energy directly. The heat energy from the sun is used first to heat the water and generate steam which in turn, is used to rotate the turbo alternator to generate electricity. The collection of solar energy is done by the solar concentrator to increase the efficiency of the system. From concentrator, the heat energy is transferred to the working fluid, water. It is possible to obtain high temperatures so that steam can be generated for running the turbine. A simplified schematic diagram of a solar power plant is shown in Figure 1.1. Further research and development activities may make it possible to install and successfully operate solar power plants of 100 MW capacities each.

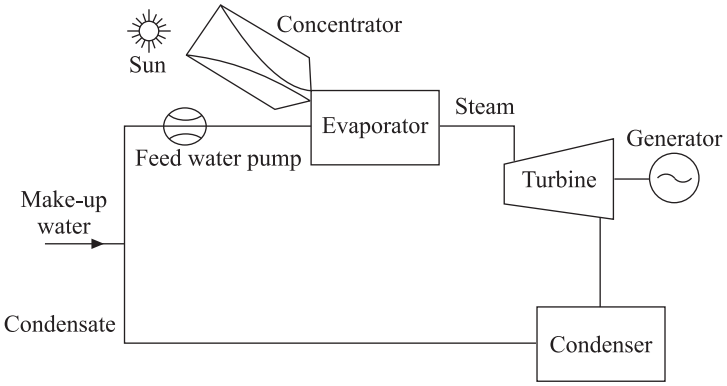


Figure 1.1 Schematic diagram of a solar power plant.

1.3.3 Tidal Power

The potential and kinetic energies of the tides of ocean and sea offer another non-conventional source of energy. It is scientifically proved that tides are formed due to gravitational forces of the sun and the moon acting on the waters of revolving earth. There are two ways of producing electrical energy from tides. Constructing a dam enclosing a portion of the sea and filling it to a height which can be maintained at a level by the tide waves and making use of that head to generate electricity, is one of the ways. The maintainable head will be little less than the maximum height of the tides produced. It can be a small capacity hydel power station with low head turbines like Kaplan turbine installed. Another way is by collecting and directing the tide water to run through turbine as the tide subsides. Huge capital cost involved has slowed down the progress in this line. At present, some tidal plants are operating in France. Researches are going on elsewhere to make such projects economically viable.

1.3.4 Geothermal Power

The heat energy available in the earth at a depth of about 5 to 10 km can be considered as another source of non-conventional energy. Volcano results when the hot fluid comes out of the earth's surface through some weak path. When groundwater comes in contact with such hot fluid, it becomes steam and comes out through bore. The hot fluid, called 'magma', also contains water. Such water may get converted into steam and gets released. The steam coming out as above could

be utilized for power generation. Geothermal power plants are existing in countries like Italy, United States of America and Newzealand. These power stations adopt either direct non-condensing cycle or indirect condensing cycle as shown in Figure 1.2 and Figure 1.3.

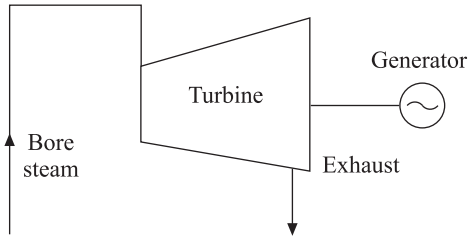


Figure 1.2 Direct non-condensing geothermal cycle.

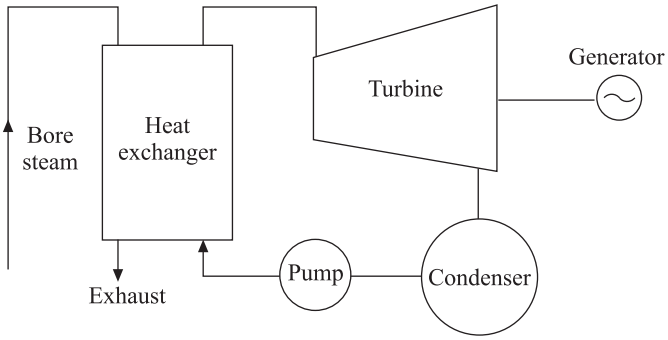


Figure 1.3 Indirect condensing geothermal cycle.

A typical indirect condensing geothermal plant being operated in United States of America is shown in Figure 1.4. It is expected that in future geothermal source may become a favourable one.

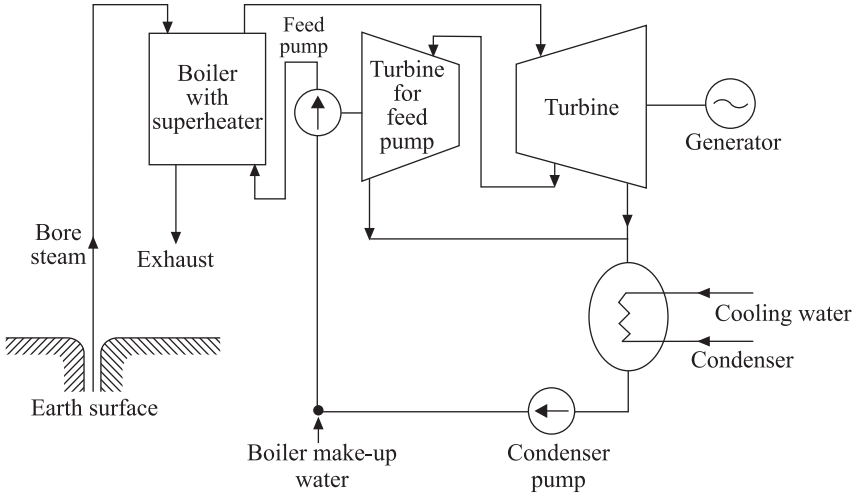


Figure 1.4 Typical geothermal plant.

1.3.5 Magnetohydrodynamic (MHD) Power

According to Faraday's law of electromagnetic induction, electromotive force (emf) is induced in a conductor moving in magnetic field. Magnetohydrodynamics study proved that such a conductor may be a gaseous one also. Hence when ionized gas or plasma is made to travel through strong magnetic field, direct current potential is produced. Here the attempt is to make use of the fuel to directly generate electricity after burning it instead of generating heat energy to produce steam to drive turbo alternator to generate electricity. A lot of intermediate energy conversions can thus be avoided. The basic principle of an MHD generator is schematically shown in Figure 1.5. The positive and negative ions of the ionised gas are collected with the help of metallic collecting plates. The direct current thus produced can be converted into alternating current with the help of an inverter.

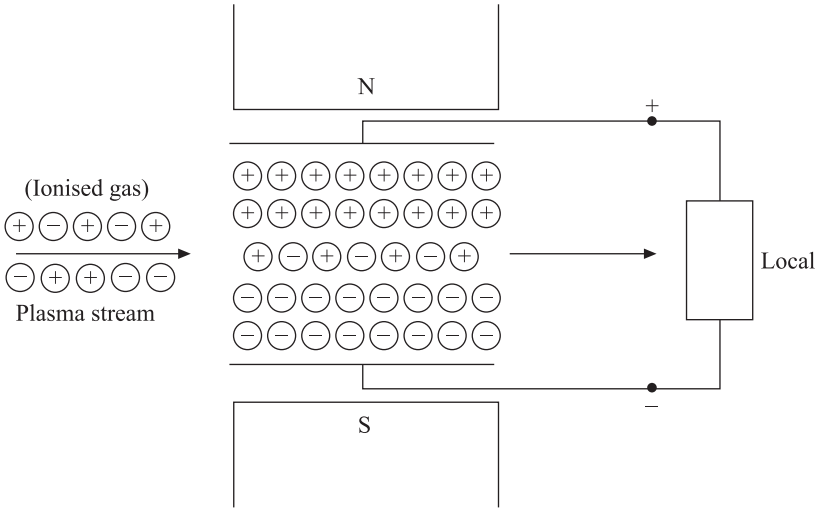


Figure 1.5 Basic principle of MHD generator.

Instead of operating MHD unit alone for producing electricity, it is beneficial to operate in conjunction with conventional steam thermal power plant. The heat energy coming out of the MHD duct can be reused to produce steam which in turn, can run turbo alternator. One such scheme is simplified and shown in Figure 1.6 for understanding purpose.

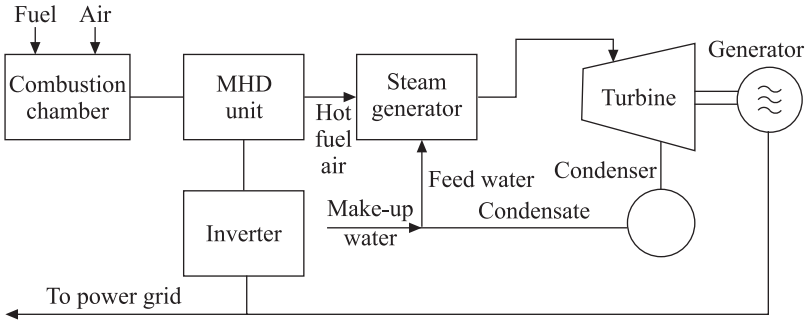


Figure 1.6 Combined MHD and conventional steam power plant.

1.3.6 Fuel Cells

The direct conversion of chemical energy of a fuel into electrical energy is carried out using fuel cells. Hydrogen or a mixture of compounds containing hydrogen is used as fuel for these cells. The anode of the fuel cell receives fuel, say H_2, and the cathode is fed with air containing O_2. The electrons (e^-) from the fuel pass through load where as the protons (H^+) pass through electrolyte and reach cathode. The electrons also after passing through electrical load as electrical energy reach cathode. In cathode the protons and electrons reunite to form H_2 and combines with O_2 to form water. A typical representation of fuel cell is given in Figure 1.7. Smaller size fuel cells of 5–10 kW capacity and larger size ones of 50 to 1000 MW capacity are aimed nowadays.

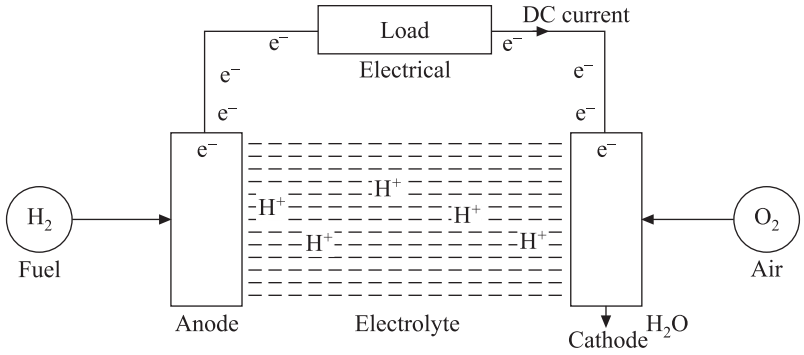


Figure 1.7 Fuel cell.

1.3.7 Biomass Power

This may be regarded as tomorrow's technology for generating electrical energy. Electricity is produced by using low cost renewable energy sources, such as wood and briquetted biomass as the primary feedstock. Rice husk, wood refuse, saw dust, wood bark, palm nut shell, sunflower seed husk, groundnut shell, coconut shell, corn cob etc, may also be utilized as an alternate fuel.

In this process, solid biomass, a carbonaceous fuel is fed mechanically into a gas generator which is embedded on a water lute in air-tight condition. Firing takes place here with controlled air supply to occur partial combustion for generation of combustible gas called *producer gas*. Ash drops on water and being taken out in the form of cinder at regular interval. To produce electrical power, the gas from the gas generator is passed through the gas washer where gas travels from bottom to top against vertical water spraying from top to clean the gas as well as to bring down its temperature. Here dirty water is being cleaned, cooled and recycled for reuse. The gas is sent to the exhauster to separate tar from the gas centrifugally and finally, to dry scrubber, where again gas is passed through filter beds for removal of carried over particles and finally, settle in gas holder.

Natural gas engines are available to operate on 100% producer gas to produce electrical power. The producer gas passes through a damper, which isolates the engine from pressure fluctuations in the gasifier and improves gas induction efficiency. A branch from the gas line passes through a valve into a blower and then into a burner for emergency flaring. A second branch of the gas line is connected to an air-line via a modified carburetor and an air gas regulator to the gas engine. Such an unit is available to generate up to 100 kWe of electricity.

Also modified diesel generating set is available which runs with duel fuel arrangement of 70% to 80% clean producer gas and 20% to 30% diesel oil to generate electrical power. By fueling duel fuel diesel engine with gasifier, more than 70% diesel oil can be saved. While running diesel generating set with gasifier mode, the gas reduced from biomass will be main fuel and the supplement being diesel oil. Figure 1.8 shows such a duel fuel system for generating electricity.

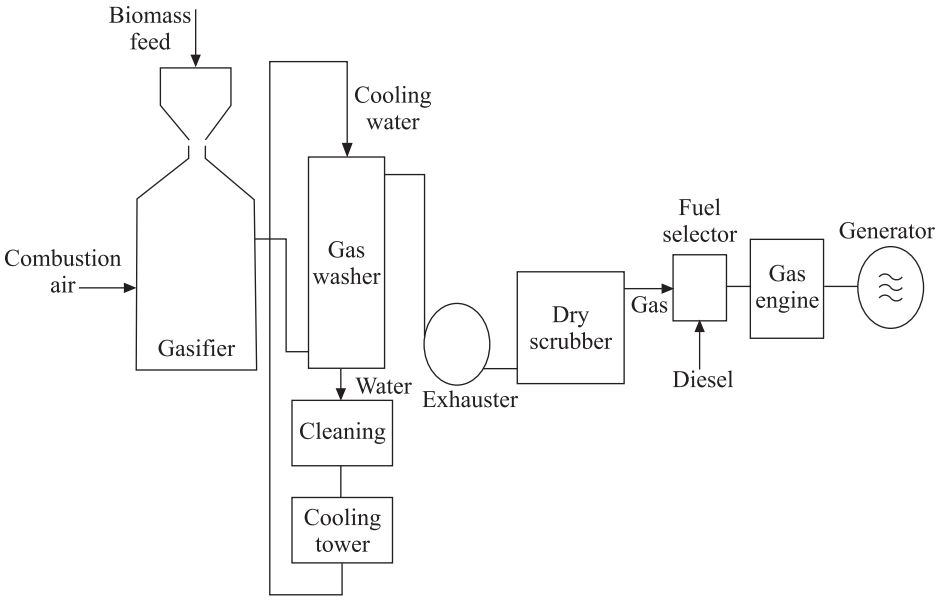


Figure 1.8 Duel biomass – diesel generating unit.

1.4 CONVENTIONAL ENERGY SOURCES

Thermal, hydel and nuclear power generating stations use conventional energy sources for producing electrical energy. Power stations of smaller capacity like diesel generation sets and gas turbine units also use conventional sources. Coal, diesel, water head, natural gas and nuclear fuel are called *conventional energy sources* used in the above power generation units. Most of the electrical energy requirement is met with conventional sources though they are not environmental-friendly like the non-conventional energy sources. Another reason may be due to lack of economical technology available to produce 100% of electrical energy through the non-conventional sources. We may have to invest heavily to install environmental protection equipment and continue with conventional routes till such time when the entire energy can be produced economically with renewable energy sources.

1.4.1 Hydropower

The potential and kinetic energy of water is converted into mechanical energy to rotate the turbine and hence the generator to produce power. Many environmental and social problems are

encountered. Flooding of a large amount of land and residential areas cause people to relocate themselves elsewhere. Also there is a belief that the area, where big dam is constructed, is prone to earthquakes.

Though there are possibilities of installing micro (≤100 kW), mini (from 101 kW to1 MW) and small (1MW to few MWs) hydro stations, the discussions here will concentrate only on hydro-electric plants of higher capacity (more than 50 MWs)

Selection of site

Selection of hydroelectric plants' location depends mainly on the following factors:

1. Location of the dam
2. Availability of water
3. Storage of water
4. Head of water
5. Transport connectivity
6. Distance from the load centre.

Classification of hydroelectric plants

There are many ways of doing the classification of hydel units. Many large units are built with multipurposes in mind. Controlled irrigation water supply, avoiding seasonal floods, growing fish and meeting drinking water demand down line are some of the purposes other than power generation.

Conventional and pumped storage plants: In the conventional one, water is collected in a dam and its head is utilized to run the turbo-generator to produce power. Water is pumped back in a pumped storage plant during lean demand period to utilize the same during peak demand period.

Base and peak load plants: When hydel plants are operated along with other generation units, hydel plant can either be used as base load plant when enough storage of water is there or as peak load unit when the storage position is not so good. Compared to steam thermal plants, hydel plants will be able to handle peak load operation effectively. Generally conventional ones are used for base load operation and the pumped storage ones for peak load operation.

Based on Head and Discharge: Potential energy of the water head is utilized to run the turbine and in turn the generator. Potential energy to kinetic energy to mechanical energy and then finally, to electrical energy conversions take place. The whole energy conversion depends finally on two parameters namely head (level of the stored water) and discharge (the quantity of water allowed to flow through turbine). The following designs are in common use based on the above two parameters.

1. **Kaplan turbines:** Low-head (2–15 m) and high discharge.
2. **Francis turbines:** Medium-head (15–70 m) and medium discharge
3. **Pelton turbines:** High head (70–500 m) and low discharge
4. **Deriaz turbines:** Acts both as prime mover and pump and hence utilized in pumped storage plants.

Layout of hydrostation

Figure 1.9 represents the typical layout of a conventional storage-type hydrostation. The main components of the station are reservoir, dam, spillways, forebay, penstock, surge tank, valve house, prime mover, powerhouse etc,.

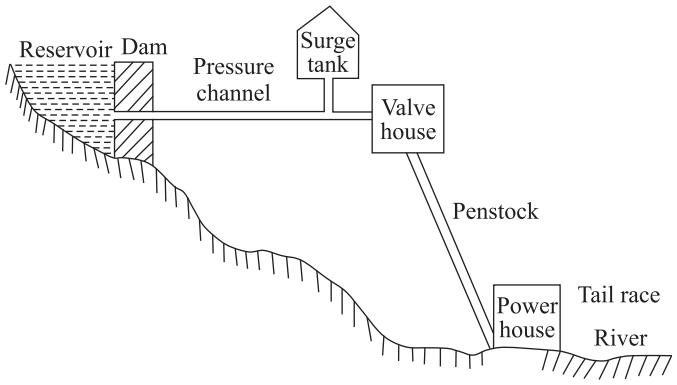


Figure 1.9 Typical layout of a hydro plant.

(a) Reservoir: The water harvested out of rain in the catchment area is collected and stored in the reservoir. The stored water can be used for power generation and for irrigation. The power production schedule will be done satisfying both the needs uniformly throughout the year.

(b) Dam: Dam is constructed in the normal path of the river to develop the reservoir to hold the rainwater harvested from the catchment area. It is also necessary to create the head required to operate the turbine. The head and storage capacity has direct relation. Dams with moderate head and large capacity or high head and moderate storage capacity can be constructed to suit the requirements.

(c) Spillways: Spill ways are constructed in the dam for safety purposes. The excess water beyond permissible level can be discharged through spillways. 'Overtopping' is a phenomenon when excess water is not discharged through spillways, but allowed to flow over the dam. Some of the common types are overflow spillway, side channel spillway and emergency spillway.

(d) Forebay: Temporary storage of water near turbine site to take care of the sudden increase or decrease of turbine load. Forebay, which is also known as head pond, is actually a surge reservoir near intake.

(e) Intake trash rack: It is added to allow the water to flow into the penstock in a controlled way and to prevent foreign elements entering the turbine.

(f) Surge tank: To take care of the system load fluctuations, a surge tank is constructed in between the dam and the valve house. It also assists penstock to take care of the water hammer caused during load fluctuations.

(g) Penstock: Penstock is water conduit or pipeline carrying water from dam to turbine. The steel pipe reinforced with concrete running between the surge tank and the turbine is called *penstock*.

(h) Prime mover (Turbine): The turbine is the heart of the hydropower station. It operates with the water head available from the dam and rotates the electrical generator coupled with it. The selection of turbine depends on head and discharge as discussed earlier. Pelton, Kaplan and Francis turbines are commonly employed.

(i) Powerhouse: Powerhouse accommodates turbine, alternator and electrical equipment. It is located normally at the foot of the dam.

(j) Tail races: The outlet water from the turbine is discharged to the river through tail race. Open channel or tunnel type tail races are possible.

(k) Electrical equipment: Electrical equipment can be broadly divided into three categories, namely alternator (electrical generator), power transformer and switch gears. Hydroelectric generators are comparatively low speed machines. Switchgears are accommodated in the powerhouse building. Transformers for stepping up the voltage and the high voltage switchyard are normally located outdoor.

Economy

Though the capital cost per MW is much higher compared to thermal power, the running cost is very less. When it is operated as a multipurpose project, the higher capital cost can be well compensated.

1.4.2 Nuclear Power

Conventional energy sources like coal, natural gas and oil are likely to last for another forty years only as per the survey conducted by International Energy Agency. Hydel sources are tapped almost to the maximum possible level. A viable alternate source left is nuclear power. About 15 to 20% of world's energy requirement is met at present by nuclear power stations. It may have to considerably improve upon to take care of future energy demand along with renewable energy sources.

There are two nuclear reactions by which nuclear energy is generated.

Fission: Nuclear power is presently generated by fission reaction. Disintegration of a nucleus into two or more nuclides is possible by hitting the nucleus with neutrons. For example, uranium nuclei can be split into two nuclides of intermediate atomic weight when hit with neutrons. If a thermal neutron strikes uranium −235 atom, oscillations are set up inside the excited nucleus. Finally, it splits into fission products involving a lot of heat energy emitted.

The following three nuclides can be fissioned by thermal neutrons with lots of probability of chain reaction.

1. ${}_{92}U^{233} \equiv$ 92 protons + 141 neutrons = 233 atomic mass.
2. ${}_{92}U^{235} \equiv$ 92 protons + 143 neutrons = 235 atomic mass.
3. ${}_{94}Pu^{239} \equiv$ 94 protons + 145 neutrons = 239 atomic mass.

These nuclides are called *fissile* materials. Of these three isotopes, only U^{235} is naturally occurring fissionable nuclide. The other two isotopes $(U^{233}$ and $Pu^{239})$ are formed from the fertile fuels, Th^{232} and U^{238} by absorption of a neutron.

The fission process of U^{235} nucleus is understandable as shown in Figure 1.10 and the equations.

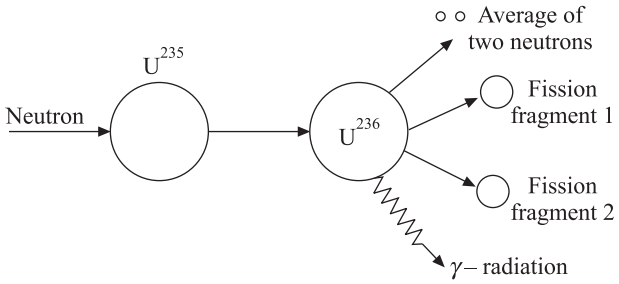


Figure 1.10 Fission process of U^{235}.

$$_{92}U^{235} + {}_{0}n^{1} \rightarrow {}_{92}U^{236} \rightarrow {}_{56}Ba^{137} + {}_{36}Kr^{97} + 2{}_{0}n^{1} + Q$$

(unstable)

The separated fragments collide with other atoms and release heat energy. The neutrons emitted help to continue a chain reaction. The complete fission of U^{235} (235 gm of uranium – 235) emits around 5.3 million kWh energy. That means, one gm of U^{235} can produce approximately 1 MW power for a day.

Fusion: The process is to combine two nuclei. On account of the repulsion forces between two nuclei, only light elements can get close enough to fuse and the rate of fusion decreases with increasing atomic number. Only isotopes of Hydrogen and Helium appear to be able to support fusion, that too at very high temperatures. Fusion process is not practiced now, but extensive research work is going on around the world.

Advantages of nuclear power

1. Nuclear energy is comparatively clean source of energy.
2. As there is no combustion process using oxygen, greenhouse gas emission is nil. Hence nuclear energy is free from greenhouse effect and acid rain.
3. Nuclear power is also cost competitive. Though initial cost is high, the operating cost specially the fuel cost is low.
4. The amount of waste produced and hence the physical effort to dispose the waste is less.
5. Fossil fuels may get exhausted in short time but not the nuclear fuel.

Disadvantages of nuclear power

1. The possibility of radiation hazard is always there.
2. Lot of expenditure has to be incurred for taking care of emergency conditions, containment of radiation, detection of radiation, and dealing with radioactive waste.
3. Mining of nuclear fuel as well as operation of nuclear power plant involves lot of human beings. In addition to those people who are working directly, the people living in and around also have to be taken care of.

4. Accidents like melting down of reactors have serious repercussions. The live examples are the accidents happened in Three-Mile Island nuclear power plant in USA during 1979, Chernobyl nuclear power plant in Ukraine (part of the then USSR) in 1986 and Fukushima, Daiichi, nuclear power plant in Japan during 2011.

Selection of site for nuclear power plants

Factors like availability of water, transport facilities through road, rail and/or sea, vicinity to load centre etc. which are common to any other power plants will also be applicable here. Because of the possibility of radiation, the nuclear power plants should be located away from populated area. While selecting the site one must also consider the nuclear waste disposal activity into account.

Main equipment of nuclear power plant

The only difference from the coal or oil-fired thermal power plants is the generation of heat energy. Instead of boiler in a conventional steam thermal power plant, nuclear power plant uses reactor and heat exchanger. The basic block diagram of a nuclear power plant is shown in Figure 1.11.

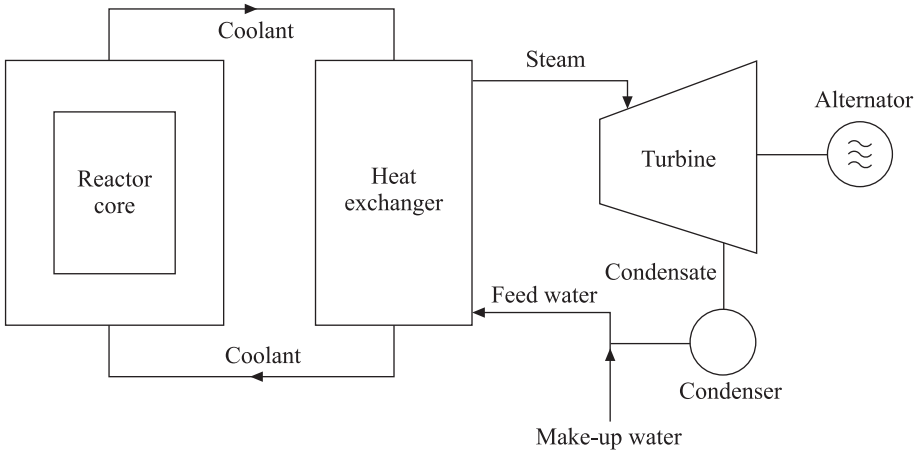


Figure 1.11 Basic block diagram of a nuclear power plant.

Main components of nuclear reactor

The primary components of a nuclear reactor are (Refer to Figure 1.12):

1. Fissionable material (fuel rods)
2. Moderator
3. Reflector
4. Reactor control rods
5. Coolant system
6. Reactor vessel and
7. Shielding

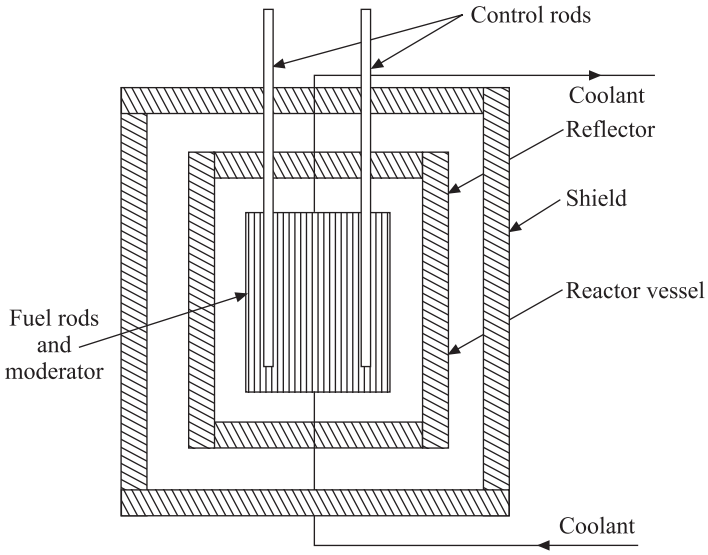


Figure 1.12 Primary components of a nuclear reactor.

1. **Fissionable material (Fuel rods):** The fissionable material is the heart of the nuclear reactor. The fissionable materials are Uranium-233, Uranium-235 and Plutonium-239. They are fissionable by neutrons of all energies. Thorium-232 and Uranium-238 require fast neutrons to cause fission. The fissionable material is filled in fuel rod tubes made of aluminium, stainless steel or zirconium.
   Critical mass: The minimum quantity of fissile material that is capable of sustaining a fission chain is called the *critical mass*.
   Multiplication factor: Multiplication factor K is defined as the ratio between the neutrons produced in one generation and the neutrons absorbed in the preceding generation.

$$K = \frac{\text{Neutrons produced in present generation}}{\text{Neutrons absorbed in the preceding generation}}$$

$$= \frac{\text{Rate of neutron production}}{\text{Rate of neutron absorption}}$$

   The system is called *subcritical* when $K < 1$, critical when $K = 1$ and supercritical when $K > 1$.
2. **Moderator:** Neutrons are classified either as thermal neutrons (slow and having energies between zero and one electron volt) or intermediate neutrons (having energies between 1 eV to 10000 eV) or fast neutrons (having energies above 10000 eV). Most reactors use thermal neutrons to sustain the chain reaction. In such reactors, a moderator is required to slow down the fast neutrons from previous fission processes. Moderation is made possible by elastic collision of the neutrons with the moderator nuclei. The moderator contains atoms of mass close to that of neutrons. Some of the proven useful moderators are water, heavy water, hydrocarbons, beryllium and graphite.

3. **Reflector:** Surrounding the core is a reflector which reflects the neutrons back into the core to prevent leakage. This action helps to maintain a high flux level within the core. The materials mentioned above for moderators are used as reflectors also. Reflector also helps the core to produce more uniformly distributed heat energy.
4. **Reactor control rods:** The reactor should have a control system so that steady power is produced in all situations. A nuclear reactor can give heat energy to produce power continuously only when the fissile material in the core exceeds the critical mass. Nuclear reactors are built in such a way that their size is greater than the critical. To control the heat energy released, the neutron flux density in the reactor has to be controlled. Addition or removal of either fuel or moderator or reflector materials can do this job. But the most commonly used method is to use neutron absorber in the form of control rods. Cadmium and Boron are alloyed with steel or aluminum for making control rods. When heat energy has to be reduced, the control rods will be inserted into the core to absorb neutrons and hence reduce the heat energy released. Similarly to increase the heat energy released, the control rods are to be moved up. That means minimum heat energy is released when the control rods are in the bottom of the core and maximum heat energy is released when the control rods are in the top position. During normal operation the control rods may occupy a position in between depending on the load. The functions of the control rods may thus be listed as below.
   (a) To start the nuclear chain reaction whenever the reactor is brought into operation from cold condition. The control rods have to be lifted up slowly.
   (b) To maintain the chain reaction and control the heat energy released by adjusting the position of the control rods as per load demand.
   (c) To shutdown the reactor as per plan or under emergency. The rods have to be lowered down either slowly or quickly as per need.
5. **Coolant system:** The heat released due to fission process is removed by circulation of a coolant. The heat energy thus carried by the coolant is transferred to the working fluid (water) to produce steam which in turn is used to drive the turbo-alternator to produce electricity. The coolant is recirculated after the heat transfer has taken place. In some reactors water is boiled within the reactor core so that the fission heat is utilised directly to produce steam. Some of the popular coolants are water, liquid metal like liquid sodium and potassium, molten salts (fluorides) and gases like Helium, Hydrogen, air and CO_2.
6. **Reactor vessel:** Reactor vessel houses the fuel core, moderator and reflector. It is generally made of steel and concrete-lined to prevent radiation.
7. **Shielding:** To protect against the radiation, shielding is provided covering the entire reactor. During the fission process α, β and γ rays are emitted also. They are to be prevented from leaking out. Concrete structure is the cheap and effective option for the shielding purpose.

Types of reactors

Nuclear reactors can be classified as thermal and fast reactors on the basis of neutron energy.

Other possible classifications are based on fuel materials used, types of cores, moderator used and coolant used. The important reactors in operation nowadays are with some combination of the above. The important ones are listed below:

(a) Pressurised water reactor (PWR)
(b) Boiler water reactor (BWR)
(c) Liquid metal cooled reactor (LMCR)
(d) Canadian deuterium uranium (CANDU) reactor
(e) Gas cooled reactor
(f) Fast breeder reactor

(a) Pressurised water reactor (PWR): The pressurised water is used as coolant, moderator and reflector. The coolant is maintained at a pressure, high enough to prevent bulk boiling in the reactor. Slightly enriched uranium is used as fuel. Figure 1.13 shows a simplified schematic diagram of a PWR power generating unit. PWR is a cheap and compact version, but operates at low thermal efficiency ($\simeq$ 20%).

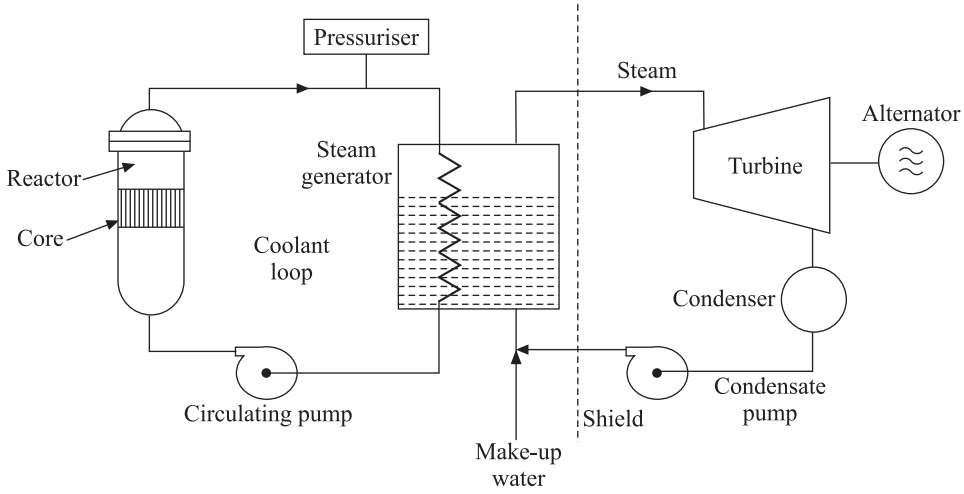


Figure 1.13 PWR power unit with water as coolant.

(b) Boiler water reactor (BWR): In this case also, ordinary water is used as moderator, reflector and coolant . Here the working fluid for steam generation itself is used as coolant. The reactor uses enriched uranium as fuel. The steam is generated within the reactor vessel itself and hence a separate heat exchanger or steam generator is not required. Thermal efficiency obtained here is better than that of PWR ($\simeq 30\%$) and is more stable. As the steam is generated in the reactor vessel, it will be radioactive. Suitable protection measures are necessary involving additional cost. Figure 1.14 shows schematically, the BWR power plant.

(c) Liquid metal cooled reactor (LMCR): Graphite is used as moderator and sodium as primary coolant. Na-K, an alloy of sodium and potassium, is used as intermediate heat exchanging fluid. Slightly enriched uranium is used as fuel. A high temperature

operation is possible with liquid metals to achieve the higher efficiency. Heat exchanging operation is taking place twice. The heat generated by the reactor is carried away by liquid sodium in the primary circuit and exchanged with Na-K liquid in the intermediate circuit. In the second heat exchanger the heat energy carried by Na-K liquid is transferred to boiler water to generate steam. Figure 1.15 shows a schematic diagram of an LMCR power unit.

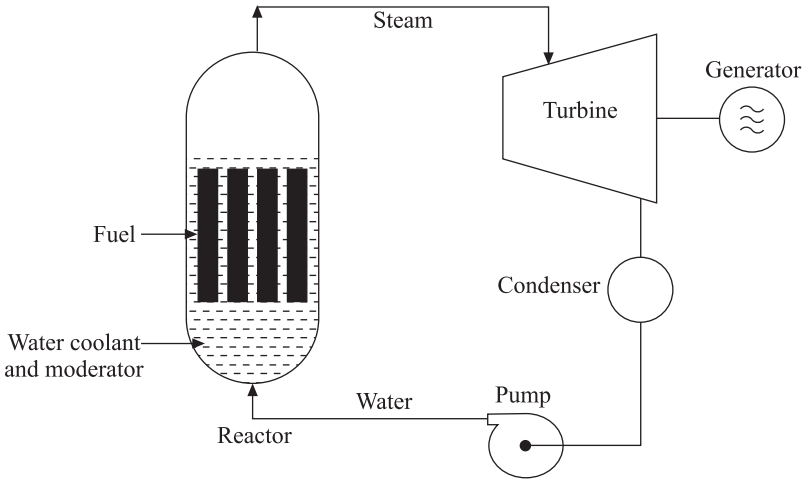


Figure 1.14 Boiler water reactor (BWR) power plant.

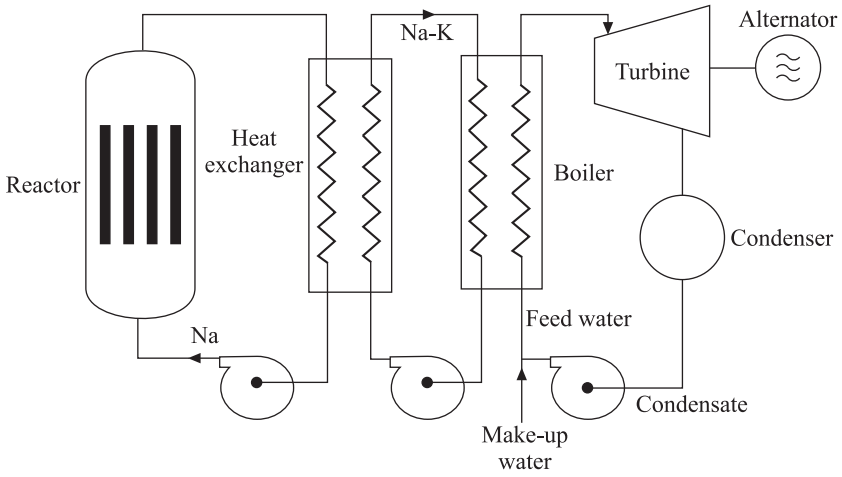


Figure 1.15 LMCR power unit.

(d) Canadian deuterium uranium (CANDU) reactor: The CANDU reactors are extensively developed and used in Canada. Heavy water, i.e. Deuterium Oxide (D_2O) is used as coolant as well as moderator. Deuterium is an isotope of hydrogen. These reactors can also be called as *pressurized heavy water reactors* (PHWR). The CANDU reactor

uses natural uranium as the fuel. The main differences between this reactor and the pressurised water reactor (PWR) are:

1. PWR uses ordinary water as coolant and moderator whereas CANDU or PHWR uses heavy water as coolant and moderator . The boiling point of heavy water is 101.4°C against 100°C and density 1100 kg/m^3 against 1000 kg/m^3 of ordinary water.
2. PWR uses enriched uranium as fuel, but CANDU uses natural uranium as fuel.

Figure 1.16 shows a schematic diagram of a CANDU or PHW reactor which is similar to that of a PWR.

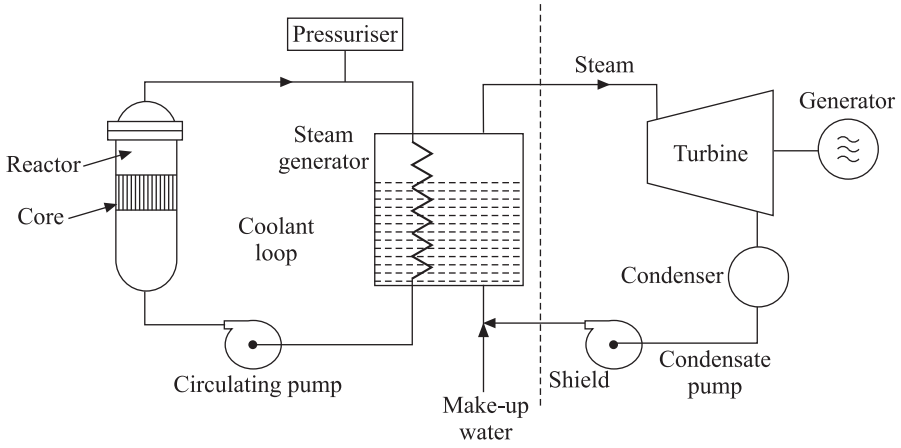


Figure 1.16 CANDU or PHW reactor unit with heavy water as coolant.

(e) Gas-cooled reactor: Carbon dioxide or helium is used as coolant and graphite as moderator in gas-cooled reactors. Though gases are inferior to water in heat transfer, gas-cooled reactors are safer compared to water-cooled ones. Natural uranium itself can be used as fuel in gas-cooled reactors. Refer to Figure1.17 for the schematic of gas-cooled reactors.

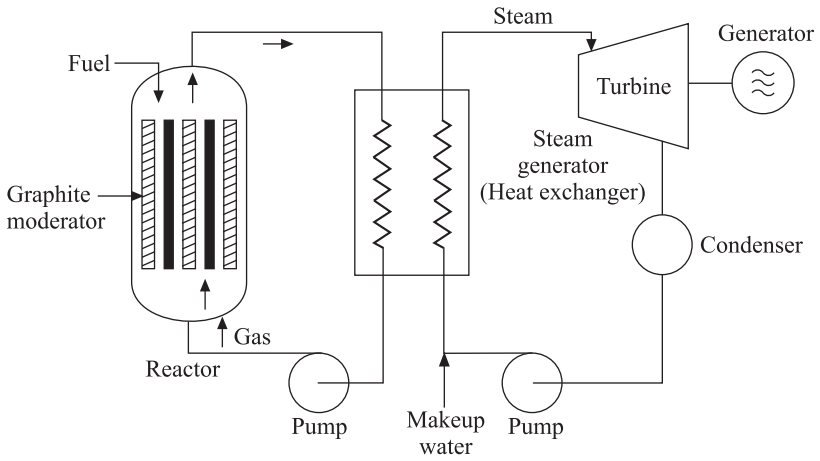


Figure 1.17 Gas-cooled reactor power plant.

(f) Fast breeder reactor (FBR): The bulk of the natural uranium exists in the form of U_{238} which is not fissionable. The natural uranium contains U_{235} in less proportion, but is fissionable. When U_{235} fissions by absorption of a neutron, it produces heat energy and also emits excess neutrons. All the excess neutrons are not required to sustain the chain reaction. Excess neutrons can be absorbed by U_{238} to produce PU_{239} which is fissionable. U_{238} used here is called *fertile isotope*. The reactors which adopt this process are called *fast breeder reactors*. The reactor starts with U_{235} and produces PU_{239} through fertile uranium U_{238}. Plutonium thus produced is more than U_{235} consumed. Fast breeder reactors normally do not employ moderators. The coolants used are sodium (Na) in the primary loop and Na-K in the intermediate loop. With the coolants as above, the reactor can also be called *liquid metal cooled fast breeder reactor* (LMCFBR). The less fuel consumption is its main advantage. The schematic diagram of one such power generation unit is shown in Figure 1.18.

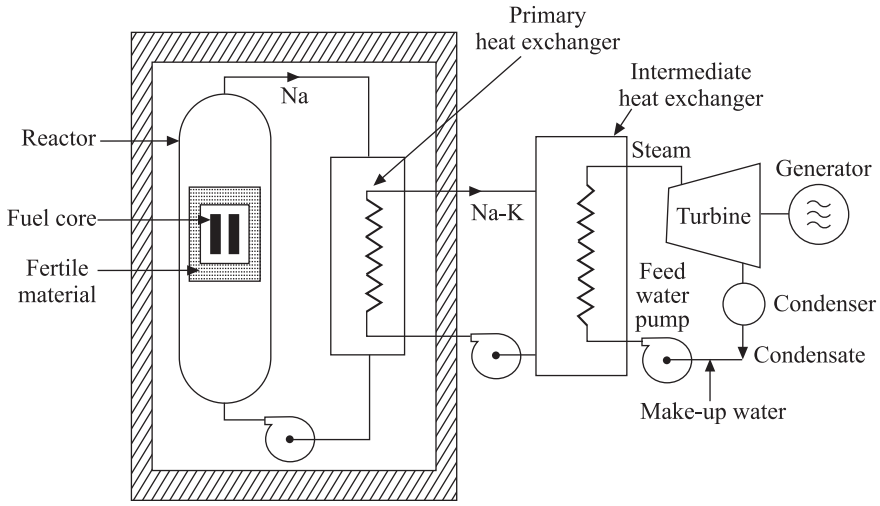


Figure 1.18 LMCFBR power unit.

1.4.3 Gas Power

Air, the working fluid, is drawn from atmosphere and compressed by an air-compressor to attain high pressure. The outlet of the compressor is fed to a combustion chamber where the fuel is injected. The fuel along with air burns and high pressure exhaust at high temperature is released. The compressed air is sometimes preheated via a regenerator exchanging heat from the gas turbine exhaust. The hot air with high-pressure coming out of combustion chamber expands and develops mechanical energy in the gas turbine. The electrical generator coupled with turbine shaft converts the mechanical energy (now rotational) into electrical energy. Part of the turbine energy is used to run the compressor also to improve the overall efficiency. A starting motor comes into picture while starting the power unit using external power or battery. Figure 1.19 shows the schematic arrangement of a gas turbine power unit.

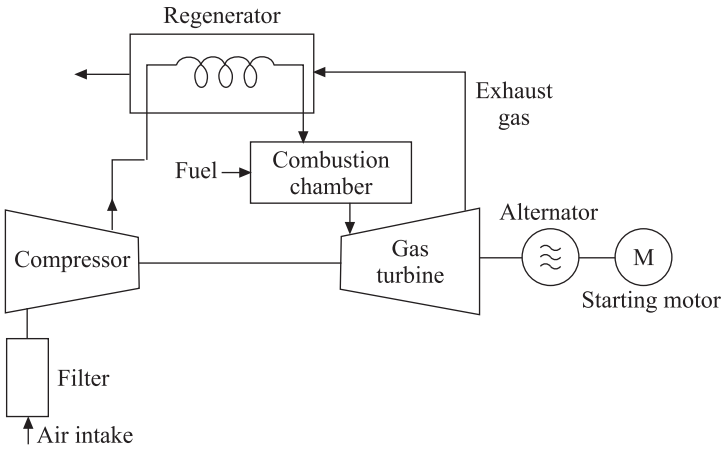


Figure 1.19 Gas turbine power plant.

1.4.4 Steam Power (Thermal Power)

The thermal power plants generate electricity using heat energy of the steam generated in the boilers. The heat energy required is supplied from fossil fuels like coal, oil and natural gas. The fossil fuels are burnt in the boiler's combustion chamber. The hot flue gas thus generated exchanges heat with feed water to generate superheated steam. The superheated steam at high pressure is expanded in a steam turbine to make it rotate. The electrical generator coupled with the turbine rotates and generates electricity. The turbine-generator combination is also called 'Turbo-Alternator'. Thermal power plants with a capacity of few MW to 1000 MW are generally constructed. Superthermal power plants of 1000 MW or more has become a recent trend. About 60 percent of the globe's power generating capacity is from steam thermal power plants. In this book we will be discussing about the operation and controls of steam thermal power plant only. As the title of the book suggests, instruments and controls of thermal power plants will be covered extensively.

Selection of site for thermal power plant

The general concept of locating the power plants near the load centres has changed here. It is advisable to locate thermal power plants near fuel pit head because of the cost involved in transporting fuels is always more than that of the cost involved in transmitting electrical energy.

A few important factors for the selection of site for thermal power plant are discussed below:

(a) Fuel supply: Availability of fuel and its transportation cost up to the boiler is an important factor to be considered. The power station should be located as close as possible to the coal mines. The economics has to be calculated taking into account the electrical energy transmission costs to different load centres.

(b) Water supply: Availability of sufficient and suitable boiler feed water, cooling or circulating water for condensers, water for disposal of ash and also drinking water for the working staff should be considered. Location of the plant near water sources like river is desirable.

(c) Land requirement: Suitable land area for present installation of the power plant and for future expansion should be available. Cost and bearing capacity of the land are the other factors to decide the site.

(d) Transport facilities: These plants can be located either near to the fuel pitheads (coal mines) or the load centres. The choice of this is made on the basis of transportation cost of the fuel and transmitting cost of the electrical energy. If the quality of coal is poor, the transportation of more coal and hence the cost of such transportation is high. In such cases it is better to locate the power plant near fuel pithead. Availability of road links and possibility of rail links are also to be considered**.**

(e) Ash disposal: A large space should be available near the plant for ash disposal. Construction of ash pond is a part of installation. Enough space and water requirements should be met.

(f) Environment requirement: Thermal power plants are capable of creating a lot of pollution problems. Emergency letting off steam may create noise pollution. Smoke from chimneys may cause air pollution. Ash handling may create both water and air pollution. Hence it is better to locate thermal power plants away from populated areas.

General layout

Schematic layout of a typical modern thermal power plant is shown in Figure 1.20

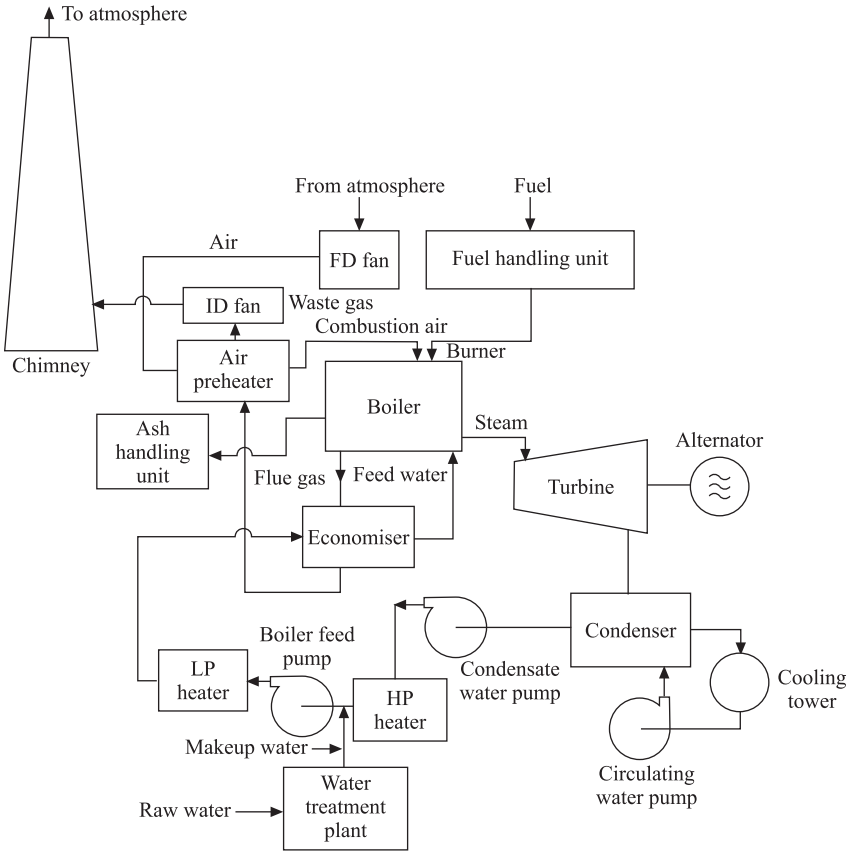


Figure 1.20 Layout of a typical thermal power plant.

The main power plant can be subdivided into several small units, namely

1. **Fuel-handling unit:** This includes fuel storage, conveyor belts, quantity measurement and control.
2. **Ash-handling unit:** It includes ash-handling plant, electrostatic precipitator, ash storage, ash disposal, ash bond etc.
3. **Boiler unit:** This includes boiler drum, air preheater, coal mills, draught system with forced and induced draft fans, economisers, superheaters etc.
4. **Feed water unit:** It includes raw water pump, make up water pump, water treatment plant, boiler feed pump, condenser etc.
5. **Cooling water unit:** It includes circulating water pump, cooling tower etc.
6. **Turbine unit:** It includes steam turbine, steam governors, speed control system, steam bus etc.
7. **Generator unit:** It consists of alternator, exciter, main transformer, switch gears etc.

Main flow circuits

The flow circuit of a thermal power plant can be divided into two main circuits, such as

1. **Water circuit:** This is further divided into:
   Feed water and steam circuit and
   Cooling water circuit
2. **Air-fuel circuit:** It is further divided into:
   Fuel-ash circuit and
   Air-flue gas circuit.

Feed water and steam circuit: Raw water from river, canal or pond is treated in a water treatment plant and dimineralised before it is being used in the boiler. This operation is required to safeguard the boiler and turbine equipment from the various bad effects of impurities present in the raw water. As the treatment costs a fortune, it is not preferable to waste the treated water. Hence the superheated steam generated out of feed water (treated water) is condensed back after its heat energy is utilized in the turbine and recirculated. The water and steam losses during the process are made up by treating the raw water and getting added to the condensed water from the turbine as makeup water. Figure 1.21 shows the steam and water flow of the steam thermal power plant.

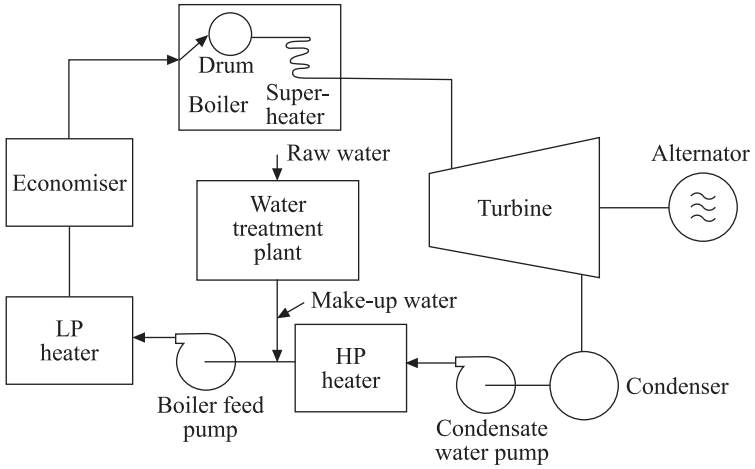


Figure 1.21 Feed water and steam flow circuit.

Cooling Water Circuit: To condense the low pressure exhaust steam from the turbine, a large amount of cooling water is required. This water is ordinary water, pumped from the sources like river, canal or pond. This water need not undergo the rigorous process of treatment like feed water. It can be recirculated after getting cooled through cooling tower. The purpose of the cooling tower is to get the heat received by the cooling water after passing through the condenser away from it so that the same water can be recirculated. One such cooling water flow circuit is shown in Figure 1.22.

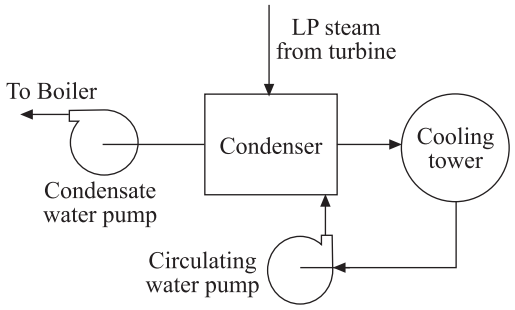


Figure 1.22 Cooling water flow circuit.

Fuel-ash circuit: Though different types of fuels can be used in a thermal power plant, coal is considered to be the main fuel. After receiving coal from the mines through various transport modes, it is stored in a coal storage yard first. Then it is crushed, sized and dried before feeding to the boilers through coal bunkers and conveyors. Coal after combustion becomes ash which has to be removed away from boiler premises for smooth running of the unit. Ash-handling plant, ash pond, ash storage yard and disposal facilities form a group of ash circuit. Figure 1.23 shows the schematic diagram of a fuel-ash circuit.

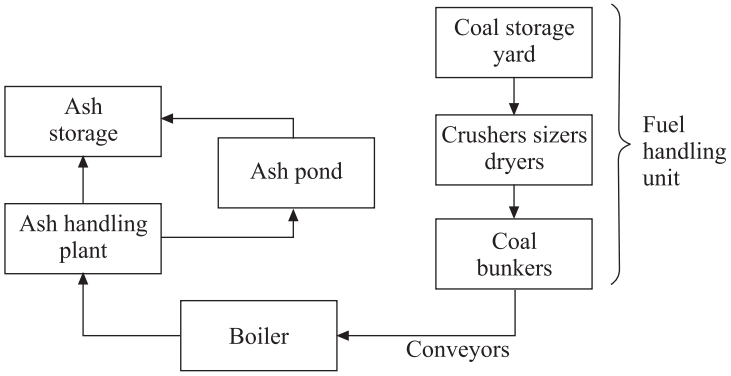


Figure 1.23 Fuel-ash circuit.

Air-flue gas circuit: Air required for complete combustion of the fuel is managed by two equipment called forced draft (FD) fan and induced draft (ID) fan. Normally, FD fan is used for supplying atmospheric air into the combustion chamber and ID fan is used to suck away the flue

gas generated out of combustion and send them back to atmosphere through chimney. The flue gas exchanges heat energy to the feed water in the combustion chamber and the superheater. Then the flue gas with less heat energy is passed through economiser and air preheater to exchange heat energy to the feed water and combustion air respectively. The flue gas coming out of air preheater is supposed to have given up all useful energy by that time. At this point the flue gas is called *waste gas* which is passed through dust collector and then to atmosphere with the help of ID fan and chimney. Figure 1.24 shows the simplified schematic diagram of the air-flue gas circuit.

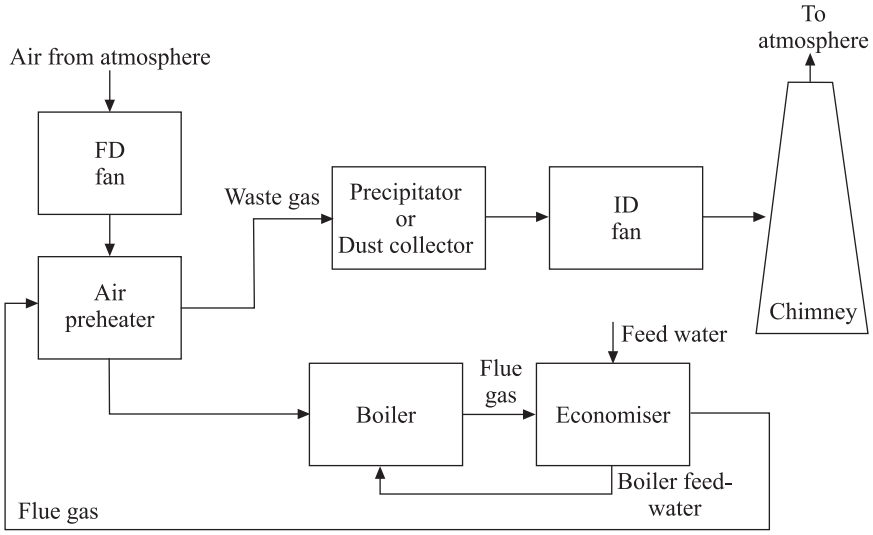


Figure 1.24 Air-flue gas circuit.

Different elements of thermal power plant

Boiler and turbo-alternator are the two main equipment in a thermal power plant. The other auxiliary equipment perform supporting functions to either of the two main equipment. Such equipment are listed below and discussed in this section.

I. Boiler	II. Turbo-alternator
(a) Boiler feed pump	(a) Steam turbine
(b) Economiser	(b) Condenser
(c) Superheaters	(c) Cooling tower
(d) Coal mills	(d) Generator or alternator
(e) Air preheater	(e) Governors/Speed controls
(f) Draught system	(f) Alternator Cooling system

(I) Boiler: It is a steam generation unit. The boiler produces steam out of feed water taking heat energy from fuel. The fuel is burnt in association with air in the combustion chamber to produce heat energy. Hot combustion gases exchange energy with feed water so that feed water gets heated up to form steam. Two types of boilers are available, fire tube and water tube. In fire tube boilers,

the hot combustion gas flows through tubes which are surrounded by water. In case of water tube boilers, the water tubes carrying feed water pass through combustion chamber where the hot combustion gases flow over them. Water tube boilers are generally preferred in power generation unit because of the high pressure and high temperature involved. Normal pressure and temperature of the steam generated will be in the order of 100 kg/cm^2 and 550ºC.

(a) ***Boiler feed pump:*** The function of the boiler feed pump is to pump the feed water required for conversion into steam in the boiler. The condensate water coming out of turbine condenser and the makeup water coming from the water treatment plant add together to form total feed water. A high capacity induction motor-driven pump is used as feed water pump. Feed pumps take the major share of internally consumed power of any thermal power station.

(b) ***Economiser:*** Economiser is basically a heat exchanger. The hot combustion gases (flue gases) after exchanging heat to the feed water through boiler tubes running in the combustion chamber and to the steam in the superheater are led through economiser. The heat energy left in the flue gases exchange heat with the cold feedwater which is fed through economiser before entering regular boiler. This operation helps to increase the overall boiler efficiency. A bundle of water tubes installed in the economiser carries feed water and the flue gases are made to flow over these tubes for proper heat transfer. The outcoming flue gases, with some more heat energy left in them, are made to flow through air preheater before going out to the atmosphere through ID fan and chimney section

(c) ***Superheater:*** In the process of converting water into steam, saturated steam is first generated in the boiler drum and the water tubes. The saturated steam may contain water droplets in it. By increasing the temperature at any pressure of the saturated steam, superheated steam which behaves like any perfect gas and without water droplets can be produced. The heat energy transfer for this purpose is carried out by the superheater. Elimination of moisture and hence the condensation of steam before reaching turbine is achieved. It also results in higher efficiency of the plant.

As superheater tubes are subjected to high flue gas temperature, they are made of special alloy steel such as chromium molybdenum. The location of the superheater is always at a place where flue gas temperature is high. Radiant type and convection type superheaters are normally used. Radiant type is of drooping characteristic and temperature goes down with increased steam out. Convection type has rising characteristic and hence temperature goes up with increased steam flow. To get constant temperature of the superheated steam at all loads, both the types are combined and installed at a suitable location.

(d) ***Coal mills:*** Coal is the main fuel for steam thermal power plants. It can be burned by using grate and stokers if the coal used is of cheaper variety and does not require complicated combustion control. In modern power plants pulverized coal is used. Pulverised coal mills are employed for crushing the coal into a powder form. Ball mill, hammer mill and roller mill are the types of mills engaged for this purpose. Once pulverized, the coal can be equated either to oil or gaseous fuel for combustion control purposes. The advantages like complete combustion and higher efficiency compensate for the high capital cost involved.

(e) ***Air preheater:*** The remaining heat energy left in the flue gases after passing through superheaters and economiser can be extracted to some extent in the air preheater. Here the heat energy is exchanged between flue gases and combustion air. Air from the FD fan is passed through air preheater before it is being sent to burners. Recuperative and regenerative preheaters are used commonly. In the recuperative type the flue gas passes through bundles of steel tubes and the air flows surrounding the tubes. In the regenerative type, air and flue gases flow on both sides of a slow moving drum made of corrugated metal plates.

(f) ***Draught system:*** For proper combustion to take place in the combustion chamber of the boiler, enough air has to be supplied. The hot flue gases generated after combustion has to be utilized in boiler tubes, superheaters, economiser and air preheater. Finally, the waste gases coming out of air preheater have to be let in the atmosphere through chimney. In summary, the combustion air, flue gas and waste gas flow has to be maintained so that the combustion process is made smooth. To overcome the resistances offered by the pipe lines, air ducts, fuel beds, dampers, chimney etc. for the flow of air and flue gases draught system is required. Normally FD fan, ID fan and chimney as a group of equipment facilitate this function. FD fan forces air into the combustion chamber with positive pressure and ID fan together with chimney creates negative pressure and sucks out flue gas from the chamber. Somewhere in between, the pressure will be atmospheric pressure. The pressure difference which makes the flow possible is called *furnace draft*.

(II) Turbo-alternator: Turbo-alternator is a physically coupled unit of steam turbine and electrical generator. Steam turbine rotates with the help of superheated steam supplied by the boiler at high pressure and high temperature. Electrical generator, which is coupled physically with turbine, also rotates with turbine to generate electrical energy.

(a) ***Steam turbine:*** Steam turbine converts the heat energy of the superheated steam into mechanical rotational energy. Impulse and reaction turbines are the two basic types. In impulse turbine, the heat energy of the steam is first converted into kinetic energy by passing through fixed nozzles. The steam coming out of the nozzles at high velocity impinges on the blades of the rotor and makes the turbine shaft to rotate finally. In reaction turbine, the steam expands partially while passing through fixed nozzles and partially over the moving blades making the turbine to rotate. High pressure (HP), intermediate pressure (IP) and low pressure (LP) stages are used to increase the shaft output. Impulse action and reactive action can be combined on the same shaft to attain higher efficiency.

(b) ***Condenser:*** Exhaust steam from the turbine is passed through condenser for two purposes. First purpose is to condense the steam into water (condensate) and recirculate as feed water to avoid treatment of raw water every time. Second purpose is to remove the incondensable gases from the water circuit. Condenser is operated at vacuum pressure for effective condensation and hence improvement in power plant efficiency. As lot of water is required for condensing, cooling water circuit is employed. Surface type and jet type condensers are the common types used in thermal power plants.

(c) ***Cooling tower:*** Ordinary water pumped from river, canal or pond is stored and used for cooling the exhaust steam from turbine in the condenser. As this process requires a large amount of water, once used water in the condenser may be cooled in the cooling

tower to remove the heat energy received from the exhaust steam and reused. Cooling tower is made of concrete with baffles provided inside. Water from the condenser is allowed to flow from top to bottom and air is circulated from bottom to top for effective cooling.

Instead of natural cooling towers employed earlier mechanical draught types are used nowadays. Induced draft type and forced draft type are the two mechanical types used. Induced draft cooling towers have the fans located on the top of the tower and sucks air from bottom whereas the forced draft ones have the fans in the bottom and forces air to flow from bottom to top. Power requirement is more for FD fan, but efficiency is more compared to ID fan.

(d) ***Generator or alternator:*** The shaft of the turbine is mechanically coupled to the shaft of the alternator. Turbine and generator together is normally called *turbo-alternator*. The speed of the generator depends mainly on the frequency. As grid is connected to all power stations such as hydel, nuclear and steam, the frequency produced has to be the same for all stations. Because of the fact that the efficiency is more at high speeds for steam turbines and at low speeds for hydro turbines, to match the speed and frequency, the number of poles have to be suitably selected for the generators. The governing equation is given by the formula.

$$N = \frac{120\,f}{P} \text{ rpm}$$

where

N = Speed in rpm

f = Frequency of the system (= 50 Hz for India)

P = Number of poles

The highest speed we can expect for a steam turbo-alternator system will be at minimum poles, i.e. at $P = 2$.

$$N = \frac{120 \times 50}{2} = 3000 \text{ rpm.}$$

(e) ***Governors (speed controls):*** It is mandatory that the frequency of the generator has to be maintained at 50 HZ plus or minus allowed tolerance limits. It means that the generator should run at constant speed irrespective of load changes. Since the generator is coupled to turbine, the speed of the turbine should be maintained constant. When the electrical load increases, the speed of the turbine will get reduced and the reverse happens when the electrical load decreases. Hence a governing system or speed control system is required. In other words, the quantity of steam admitted to the turbine should be controlled to maintain the shaft speed constant. Mechanical governors or electronic speed control is required to do this function.

(f) ***Alternator cooling system:*** A lot of heat is generated in the windings due to copper and eddy current losses. Unless the heat generated is taken away on continuous basis, the insulation of the windings may get damaged. Open-circuit cooling and closed circuit cooling methods are available depending on the size of the generator. For low capacity generators, open-circuit cooling system, where air is blown from one side and discharged to atmosphere on the other side with the help of a fan, is employed. Medium capacity

generators adopt closed-circuit system wherein, the same air is recirculated after cooling the hot air coming out of the generator. For larger units, closed-circuit hydrogen cooling is employed. Here air is replaced by hydrogen. Though hydrogen cooling is expensive and the risk of formation of explosion mixture is involved, it is used considering the advantages offered. The main advantages of hydrogen cooling are: the more effective heat transfer, less ventilation losses, no oxidation risk and low noise operation. Direct water cooling is not attempted though theoretically possible.

Efficiency of thermal power plants

The three main components of a thermal power plant are boiler, turbine and alternator. Hence the overall thermal power plant efficiency depends on the efficiencies of these three components.

Boiler efficiency: Though boiler efficiency refers to the heat input given to feed water by the furnace and the heat content of the superheated steam coming out of the boiler, the overall thermal efficiency of the boiler is the product of furnace efficiency and boiler efficiency. That means, the percentage of the higher heating value of the coal or fuel which will be present in the outlet steam is overall thermal efficiency which is usually, though wrongly, called *Boiler efficiency*. Typically the efficiency varied from 60 to 75%. With economiser and air preheater it can be improved to 70 to 85%. With modern equipment and advanced control system in position, the boiler efficiency can be increased to 80 to 90%.

Turbine efficiency: The heat energy carried by the steam at high pressure and temperature is converted into mechanical energy by expanding. The pressure and temperature are lowered down after passing through the turbine. The turbine efficiency varies from about 25 to 35%.

Alternator efficiency: Normally the efficiency of electrical equipment is higher compared to mechanical components like furnace, boiler and turbine. Depending on the size and cooling system, the alternator efficiency can be anywhere between 94 to 99%.

One may expect the overall efficiency of a steam thermal power plant to be:

$$\begin{aligned}\text{Overall efficiency} &= \text{Boiler efficiency} \times \text{Turbine efficiency} \times \text{Alternator efficiency} \\ &= (80 \text{ to } 90) \times (25 \text{ to } 35) \times (94 \text{ to } 99)\ \% \\ &= 19\% \text{ to } 32\%.\end{aligned}$$

1.4.5 Comparison of Various Conventional Power Plants

We have seen briefly about the following four conventional power plants.

1. Hydel power plant
2. Nuclear power plant
3. Gas power plant
4. Thermal (steam) power plant.

Each one is unique in converting the energy from one form into other and finally, to electric power. In the hydel power plant, power is generated by converting potential and kinetic energy of water. In nuclear power plants, the heat is generated with the help of nuclear fission. The heat is used for production of electrical energy via heat exchanger, turbine and alternator. When natural gas is used as fuel for running power plants, it is called *gas power plant*. Here, air is used as the

working fluid. Air is compressed and heated in a combustion chamber by burning fuel. The hot air moves to the gas turbine where it expands and delivers mechanical energy which in turn, is converted into electrical energy. Coal is the main fuel used in thermal power plants. Coal is fired to generate heat that is used to produce steam in a boiler. Steam is passed through a steam turbine which in turn, rotates the alternator to produce electricity.

Table 1.1 compares the salient features of the above four conventional power plants.

Table 1.1 Comparison of power plants

S.No.	Features	Hydel power plant	Nuclear power plant	Gas power plant	Thermal (steam) power plant
1.	Site	Where a large quantity of water with sufficient head available (Near catchment area and dam)	Near load centre, but away from thickly-populated area	Anywhere	Near load centre or near pit head
2.	Initial cost	Highest because of civil works	Higher	Lowest	Lower
3.	Running cost	Lowest	Highest	Higher	Lower
4.	Maintenance cost	Lowest	Highest	Lower	Higher
5.	Transmission and distribution cost	Highest	Lower	Lowest	Higher
6.	Impact on environment	Lowest	Moderate	Lower	Higher
7.	Overall efficiency	Most efficient $\simeq$ 85%	Moderate $\approx$ 30%	Quite efficient $\approx$ 40%	Less efficient $\approx$ 25%
8.	Starting	Instant	About 1/2 an hour	Few minutes	About an hour
9.	Space requirement	Maximum	Least	Less	Moderate
10.	Application	Peak or base load	Base load	Peak load or standby unit	Base load
11.	Reliability	Most reliable (when enough water storage is there)	Reliable	Reliable	Less reliable

Table 1.2 shows the total installed power generation capacity of our country as on 31-07-2012.

Table 1.2 Installed power generation capacity in India (As on 31-07-2012)

S.No.	Source	Capacity in MW	Percentage
1.	Thermal (Coal, gas and oil)	1,37,386	66.56
2.	Hydro	39,291	19.03
3.	Nuclear	4,780	2.31
4	Renewable energy sources	24,999	12.10
	Total	**2,06,456**	**100.00**

Source: CEA

Renewable Energy Sources (RES) include, Small Hydro Projects (SHPs), Biomass Gasifier (BG), Biomass Power (BP), Urban and Industrial (UI) Waste Power, Wind Energy and Solar Power.

Table 1.3 shows the capacity addition target for the XII plan (April 2012 to March 2017) period.

Table 1.3 Capacity addition target for XII plan (April 2012 to March 2017)

S.No.	Source	Capacity in MW (Original Plan)	Capacity in MW (Revised Plan)
1.	Thermal (Coal, gas and oil)	63,781	63,781
2.	Hydro	9,204	9,204
3.	Nuclear	2,800	2,800
	Total (excluding RES and Imports)	**75,785**	**75,785**
4.	Renewable Energy Sources (RES)	18,500	30,000
5.	Imports	1,200	1,200
	Total (including RES and Imports)	**95,485**	**1,06,985**

Source: CEA.

Note: During XI plan, the achievement was 54,964 MW as against the plan of 78,700 MW (i.e. 70%).

1.5 IMPORTANCE OF INSTRUMENTATION AND CONTROL IN POWER GENERATION

Meters are required to indicate, integrate, record and alarm the various parameters like flow, pressure, temperature, level, density etc. Sensing elements (or sensors), transmitters, power supplies, indicators, recorders, integrators, cabling arrangement, panels, desks, etc., are all covered under instrumentation or measuring system. Apart from these, controllers, final control elements, interfaces, programmer, etc., are added and the whole gamut of equipment is grouped as control and instrumentation system. Meter and instrument terms have been used interchangeably. In modern power plants, the cost of control and instrumentation system exceeds 10% of the total equipment cost.

Instruments are useful in many ways for a power plant operation. Instruments give accurate information about the parameters avoiding guess work on the part of attendants in charge of operation. They provide supervisors the adequate information for safe, continuous, reliable and economical operation of the plant. With proper metre readings boiler efficiency calculation, cost calculation and comparision of performance with respect to time can be done authoritatively. Measured values of the parameters like bearing temperatures, lube oil pressure, vacuum developed by the condenser, etc., help the maintenance group to take up appropriate maintenance activity before the equipment breaks down. Supervisory control and data acquisition system (SCADA) forming a part of instrumentation and control system helps to have effective control of various control loops operating and stored data required for future reference. Virtually, it has become impossible to operate power stations without the help of instrumentation and control system. In addition to mechanical and electrical crew members, the third most important crew formed will be definitely the instrumentation and control group of people in any thermal power plant.

1.5.1 Classification of Instruments in a Power Plant

In general, the instruments used in power plant can be broadly classified into mechanical instruments which measure parameters like temperature, pressure, flow, level, speed, etc., and electrical instruments which measure voltage, current, power, energy, etc. Further classification may be based on indicating, recording, integrating and/or controlling purposes. In this text, the fundamentals and working principles of the instruments will not be discussed as it is beyond the scope of this book. They are only listed here for the convenience of the readers.

Mechanical instruments

1. **Temperature measurement:** The following devices are used for the temperature measurement.
   - **(a) Liquid-filled thermometers:** It is used for measuring temperature of condensate, circulating water, feed water, bearing oil etc. They are necessarily local mounted ones, but can be used as check on remote reading thermometers.
   - **(b) Gas-filled bulb and tube thermometers:** It is used for measuring temperature of gases or liquids up to 500ºC and indicate or record the same at a point as far distant as 100 m from the location of the bulb.
   - **(c) Vapour pressure thermometer:** It can be used to measure temperature up to about 250ºC. It consists of a bulb, partially filled with a liquid connected to a length of tubing.
   - **(d) Electrical resistance thermometer (RTD):** It is used for accurate measurement of feed water, condensate, bearing oil, lubricating oil and winding temperatures for remote transmissions.
   - **(e) Thermocouples:** This can be used for measuring high-range temperatures, such as furnace flue gas, preheated air, water after economizer, steam temperatures for remote transmissions.
2. **Pressure measurement:** The following are used for measuring pressure:
   - **(a) Standard Bourdon tube type pressure gauge:** It is extensively used for measuring moderate and high-pressure in the medium like steam, water, combustion air, fuel oil etc. This can be used both for local and remote indications with a tele-transmitter.
   - **(b) Helical tube or diaphragm type pressure gauge:** It is used for low pressure measurement like bleeder steam pressure, exhaust pressures, air pressures etc.
   - **(c) Vacuum gauges and manometers:** These are used for condenser vacuums, heater pressures etc.
   - **(d) Draft gauges:** It is used to measure low pressures like furnace draft, furnace pressure, FD fan and ID fan pressures etc.
3. **Flow measurement:** The following are used to measure the flow:
   - **(a) Steam flow meters:** It is used to measure individual boiler output, group boilers output, turbine input etc. with a suitable sensor like orifice in the pipeline.
   - **(b) Water flow meters:** It is used to measure condensate, feed water, pump discharges, cooling circuit water, raw water etc.
   - **(c) Air flow meters:** It is used to measure flow of combustion air at different zones and total air flow.

(d) **Atomised steam/Air flow meter:** This can be used to measure the quantity of either steam or air used for atomization of oil fuel.

4. **Fuel measurement:** The following are the methods used to measure the quantity of fuels:
   (a) **Coal:** It is weighed in batches when in intermediate hoppers using load cells. Belt conveyor weighers are also used.
   (b) **Gas meters:** They are either differential head type (predominantly used) or positive displacement type (occasionally used).
   (c) **Oil meters:** Positive displacement type, differential head type or variable area (Rotameter) type meters are used.
5. **Level measurement:** Water level in boiler drum and other tanks, oil level, coal level in bunkers and pulverized coal bins etc. are measured.
6. **Speed measurement:** Tubine speed, other large motors speed, grate speed, conveyor belt speed etc are some of the speeds measured normally in a power plant.
7. **Gas analysis:** CO + H_2, CO_2 and O_2 measurements in flue gases, SO_x and NO_x components in the waste gases, calorific value of fuels etc. come under this category.

Electrical instruments: The following are used as electrical instruments:

1. **Ammeters:** Ammeters are used in generator leads, feeder circuits, auxiliary power circuits and field circuits.
2. **Voltmeters:** Voltmeters are used in measuring generating and transmitting voltages, various other feeding voltages, auxiliary motor voltages etc.
3. **Wattmeters:** Show power generated and feeder powers.
4. **Other meters:** Synchroscope, power factor meter, frequency meter, reactive volt ampere-meters, etc. are some other meters commonly used in any power plant.

1.5.2 Objectives of Instrumentation and Control

Instrumentation and control of a power plant is a broad subject that includes in addition to on-line operation of various control loops, the starting and stopping of equipment, the total start-up and shut down procedures as well as safety interlocks. Power plant control has a degree of complexity and sophistication that relates generally to the size and complexity of the boiler equipment being controlled. The basic objective of a control is to operate the thermal power station efficiently, economically, safely, reliably, continuously and qualitatively. This basic objective can be split down into a number of small objectives to understand better as listed below:

Efficient operation of the plant

The objective is to maintain the availability or uptime of the plant. Many power plants have more than one boiler running in parallel. It is essential to maintain and upgrade the boiler control systems to assure steam availability. Modern controls are more reliable and can readily adjust to load swings caused by varying overall plant operations. That is, to provide a continuous supply of steam at the desired condition of pressure and temperature.

Economic operation of the plant

To continuously operate the boiler at the lowest cost the following steps can be followed:

(a) Improve the combustion efficiency to reduce fuel consumption by reducing excess air. (by adopting excess air optimization control).
(b) Increase the thermal efficiency of the boiler.
(c) Provide a flexible control strategy to reduce or eliminate process upsets.
(d) Minimise steam consumption per unit of power generation in the turbine.
(e) Minimise blow down.
(f) Optimisation of boiler operations by proper load sharing among boilers.
(g) Plan for proper maintenance schedule and have maintenance guidance plan.
(h) Readily make data available for remote monitoring to determine process unit optimization, boiler efficiency and load allocation.

Safe operation of the plant

It is essential to provide safety to men and machine in the plant. A modern control system will provide tight integration with the flame safety or burner management system to improve safety. Having access to field data, diagnosis, and alarms, coupled with modern electronic controls, one can achieve the desired level of safety and security.

Pollution control

Failure to comply with pollution control regulations can be as costly as lost utilities. Government mandates enforced by fines, threat of closure, or imprisonment will usually provide sufficient incentive to comply with the regulations and modernize controls accordingly. By accurately controlling oxygen, fuel flow, and stack temperature one will see reductions in plant emissions through chimney. Similarly controls may improve the condition of effluent water and ash disposals.

1.6 PIPING AND INSTRUMENTATION DIAGRAM (P AND I DIAGRAM)

Piping and instrumentation diagram, called in short as P and I diagram, is the one which represents symbolically the process material flow along with measuring instruments and controls necessary for that process. Standard symbols are used for representing the pipeline, sensors, transmitters etc. From this, one will be able to find out the interconnected package of control loops and functions into which a number of inputs are connected and a number of outputs are delivered to final control devices. This textbook deals with the logic involved in the control systems and is independent of the type of, or manufacturer of the control hardware that is used to implement the control schemes.

There are mainly two standards for diagramming control systems such as those for boiler control. They are:

1. Instrument Society of America (ISA).
2. Scientific Apparatus Makers Association (SAMA).

The ISA system is somewhat hardware-oriented and procedures for showing pure application logic are not as clear-cut as those of the SAMA system. The SAMA system deals only with the control logic involved and are applicable to the older pneumatic or electric analog control and equally to the newer microprocessor control. Both the methods have now become the generally accepted method for diagramming boiler control systems because of their frequent use.

Tables 1.4(a) to (d) and Tables 1.5 (a) to (c) give the essence of ISA and SAMA systems respectively. Table 1.4 shows the ISA diagramming system.

Table 1.4(a) Instrument line symbols

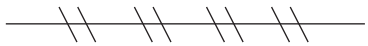
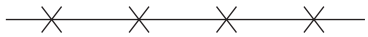
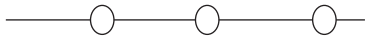
1.	Instrument supply or connection to process	
2.	Undefined signal	
3.	Pneumatic signal	
4.	Electric signal	
5.	Hydraulic signal	
6.	Capillary tube	
7.	Guided electromagnetic or sonic signal	
8.	Unguided Electromagnetic or sonic signal	
9.	Internal system link (Software or data link)	
10.	Mechanical link	

Table 1.4(b) General instrument symbols

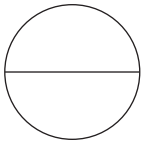
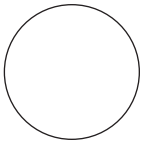
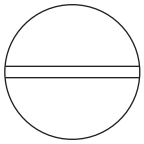
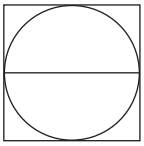
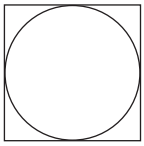
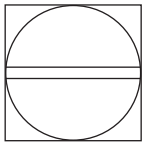
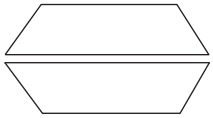
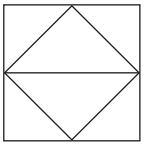
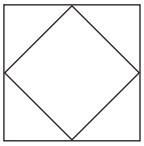
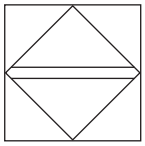
	Primary location (Accessible to operator)	**Field mounted**	**Auxiliary location (Accessible to operator)**
Discrete instruments			
Shared display, Shared control			
Computer function			
Programmable logic control			

Table 1.4(c) General function symbol

S. No	Function	Symbol
1	Summing	Σ
2	Averaging	Σ/n
3	Difference	Δ
4	Proportional	k 1:1 2:1
5	Integral	$\int$
6	Derivative	d/dt
7	Multiplying	$\times$
8	Dividing	$\div$
9	Root extraction	$\sqrt[n]{\ }$
10	Exponential	x^n
11	Nonlinear or unspecified function	$f(x)$
12	Time function	$f(t)$
13	High selecting	$>$
14	Low selecting	$<$
15	High limiting	$\not>$
16	Low limiting	$\not<$

(*Contd.*)

Table 1.4(c) General function symbol (*Contd.*)

S. No	Function	Symbol
17	Reverse proportional	$-k$
18	Velocity limiter	
19	Bias	+
		−
		±
20	Convert	*/*
21	Signal monitor	** H
		** L
		** HL

Table 1.4(d) Identification letters

	First-letter	Succeeding-letters	
	Measured or initiating variable	Readout or passive function	Output function
A	Analysis	Alarm	
B	Burner, combustion	User's choice	User's choice
C	User's choice		Control
D	User's choice		
E	Voltage	Sensor (primary element)	
F	Flow rate		
G	User's choice	Glass, viewing Device	
H	Hand		
I	Current (electrical)	Indicate	
J	Power		
K	Time, time schedule		Control station
L	Level	Light	
M	User's choice		
N	User's choice	User's choice	User's choice
O	User's choice	Orifice, restriction	
P	Pressure, vacuum	Point (test) connection	User's choice

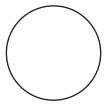
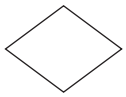
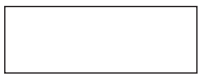
(*Contd.*)

Table 1.4(d) Identification letters (*Contd.*)

	First-Letter	Succeeding-letters	
	Measured or initiating variable	**Readout or passive function**	**Output function**
Q	Quantity		
R	Radiation	Record	
S	Speed, Frequency		switch
T	Temperature		Transmit
U	Multivariable	Multifunction	Multifunction
V	Vibration, Mechanical Analysis		Valve, Damper, Louver
W	Weight, Force	Well	
X	Unclassified	Unclassified	Unclassified
Y	Event, State or Presence		Relay, Compute, Convert
Z	Position, Dimension		Driver, Actuator, Unclassified final control element

Tables 1.5(a) to (c) Scientific Apparatus-Makers Association (SAMA) diagramming system.

Table 1.5(a) Enclosure symbols

Function	Symbol
Measuring or read out	
Manual signal processing	
Automatic signal processing	
Final controlling	

Within a circle use a letter symbol from Table 1.5(b), and within other enclosures use a symbol from Table 1.5 (c).

Table 1.5(b) Measuring / Read out letters

Process variable	Function
A - Analysis*	R – Recording
C - Conductivity	(Recorder)
D - Density	I – Indicating
F - Flow	(Indicator)

(*Contd.*)

Table 1.5(b) Measuring / Read out letters (*Contd.*)

Process Variable	Function
L - Level	Q – Integrating
M - Moisture	(Totaliser)
P - Pressure	U – Data Acquisition
S - Speed	System (DAS)
T - Temperature	RT – Recording
V - Viscosity	Transmitter
W - Weight	IT – Indicating
Z - Position	Transmitter

* Self-defining symbols such as O_2, pH etc. can be used in place of A.

Table 1.5 (c) Signal processing symbols.

Function	Symbols	Function	Symbols
Summing	Σ or +	Integrator or totaliser	Q
Averaging	Σ/n	High selecting	>
Difference	Δ or –	Low selecting	<
Proportional	K or P	High limiting	$\not>$
Integral	$\int$ or I	Low limiting	$\not<$
		Reverse proportional	$-K$ or $-P$
Derivative	$\frac{d}{dt}$ or D	Velocity limiting	V $\not>$
Multiplying	×	Bias	±
Dividing	÷	Time function	$f(t)$
Root extraction	$n\sqrt{}$	Variable signal generator	A
Exponential	x^n	Transfer	T
Non-linear function	$f(x)$	Signal monitor	$H/$, H/L,$/L$
Tri-state signal (Raise, hold, lower)	↕		

Note: The complete symbol consists of an enclosure symbol [Table 1.5(a)] within which is contained a measuring or read out letter [Table 1.5 (b)], or a signal processing symbol [Table 1.5 (c)]. Complex functions are represented by the combinations of these basic symbols.

1.6.1 Examples of ISA Instrumentation Diagramming Symbols

Temperature transmitter

Temperature sensing element

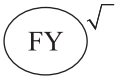
Temperature indicating controller

Temperature recording (regulating) controller

Analyser with transmitter

Oxygen analyser

Differential pressure transmitter



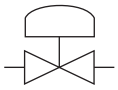
Square rooting for flow signal

Averaging temperature

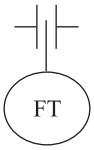
Multiplying different input temperature signals

Flow bias and gain

Flow regulating controller output in percentage



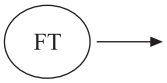
Final control element



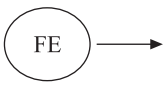
Differential pressure element (orifice) with flow transmitter

Dampers, vanes, flaps etc.

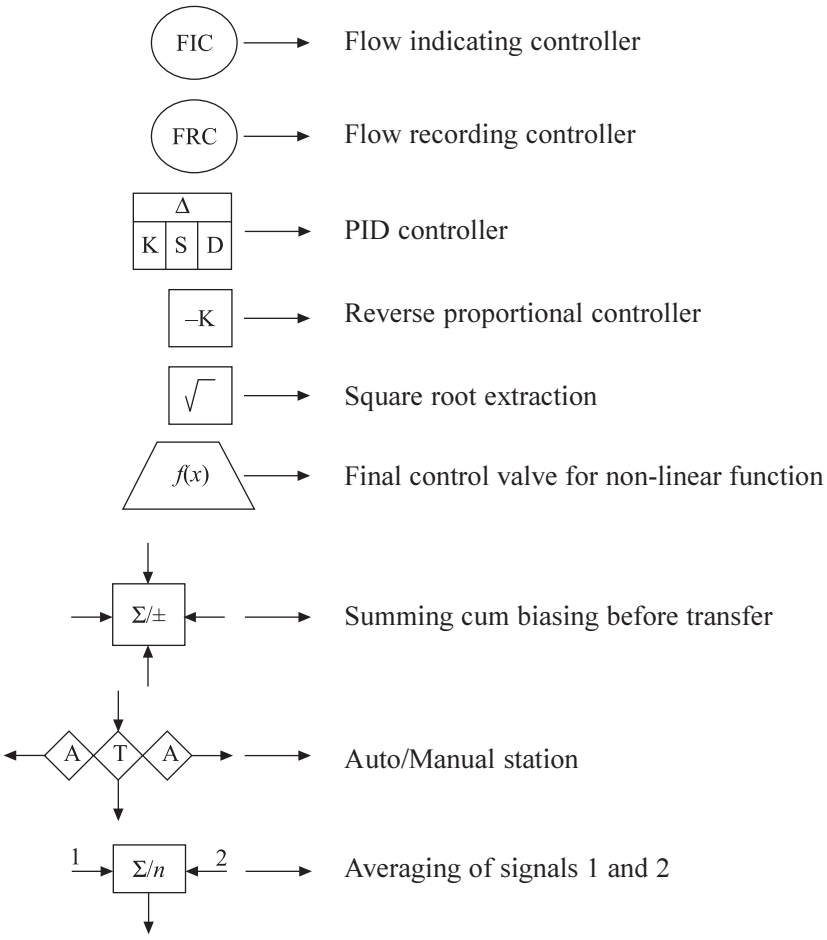
1.6.2 Examples of SAMA Instrumentation Diagramming Symbols



Flow transmitter



Flow sensing controller



1.6.3 Examples of ISA and SAMA Diagramming

Figure 1.25 demonstrates the SAMA and ISA diagramming systems for a simple two-element feedwater or drum level control system for a boiler.

In the two-element control, steam flow is measured using flow transmitter FT along with boiler drum level using LT. The steam flow signal is linearised using a square root extractor before it is being used in a feed forward control loop to anticipate the need for an increase/decrease in feed water to maintain a constant drum level. The feedback control from drum water level is shown as proportional (K) control. The control valve is characterised so that the control signal versus feed water flow is linear. For this system to perform properly and hold the drum level at the set point, it is necessary that the differential pressure across the feed water control valve be predictable at each flow and that the control valve signal versus flow relationship does not change. The functional block $f(x)$ takes care of this. The other operational details of two element control will be seen later on. The aim here is only for comparative demonstration of the SAMA and ISA diagramming system.

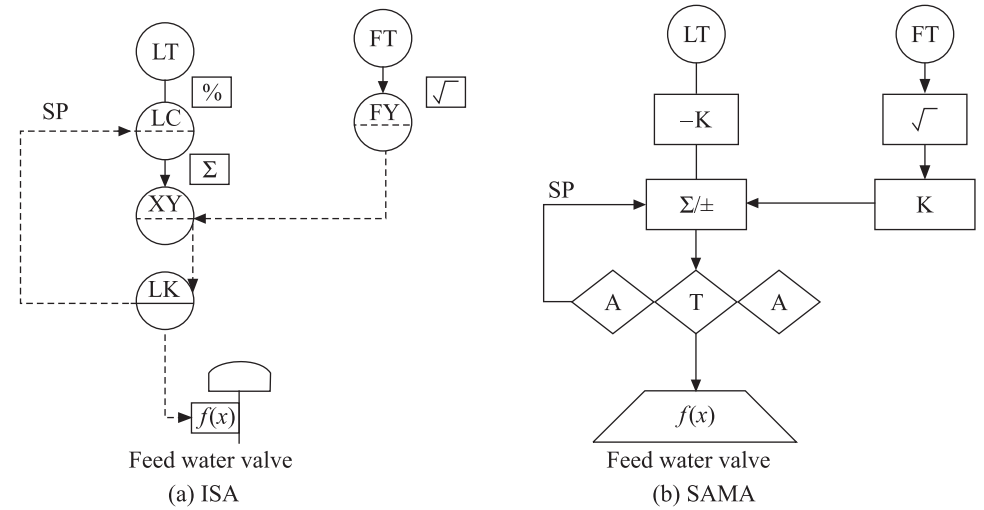


Figure 1.25 Two-element feed water control.

1.6.4 Piping and Instrumentation Diagramming

The piping and instrumentation diagram can be drawn for a particular measurement system or for a whole unit like boiler using the symbols followed by ISA or SAMA symbols. Figure 1.26 illustrates one such diagram for measurement of steam flow and control. Set point may be set manually, remotely or through another controller/computer. As the operating pressure and temperature of the steam may be different from design temperature and pressure, necessary corrections are to be made. Flow transmitter FT may give an output signal proportional to the differential head generated by head producer (like orifice) which may have to be square-rooted. The square rooting, multiplying and dividing functions are carried out in a function unit FY.

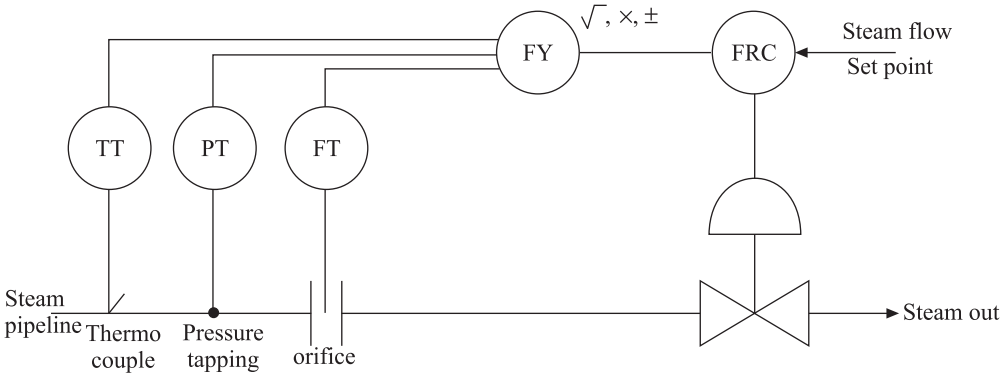


Figure 1.26 Piping and instrumentation diagram for steam flow control.

1.7 COGENERATION OF POWER

Several industries like paper mills, sugar factories, steel mills etc. require saturated steam for heating and drying purposes. The steam required is known as *process steam* or *factory steam*. In addition, they require power for various drives, lighting etc. Steam for power generation purpose is produced at high pressure and superheated to high temperature. Process steam generation can be done separately. Instead of running two-boiler units, one for power generation and the second for process steam generation, a single unit can be made to serve both the purposes. Instead of condensing the exhaust steam coming out from the power turbine, it can be utilized very well as process steam. A plant producing process steam or factory steam as well as electrical power is called *cogeneration plant*. If the basic need is for process steam, power can be produced incidentally as co-product. The ways by which cogeneration plant can operate are listed below.

(a) Back pressure turbine
(b) Pass-out turbine
(c) Process heat unit.

1.7.1 Back Pressure Turbine

By suitably designing a turbine to accept the high steam pressure at the inlet and make available the amount of process steam at desired pressure and temperature at the outlet, it is possible to generate both power and process steam through a single unit. Such a unit, called *back pressure turbine*, is shown in Figure 1.27. The condenser in a normal operation is replaced by the process heater here representing the requirement of process steam for many units like dryer, heat exchanger, etc. Otherwise the heat energy present in the exhaust steam is carried away by the cooling water in the condenser.

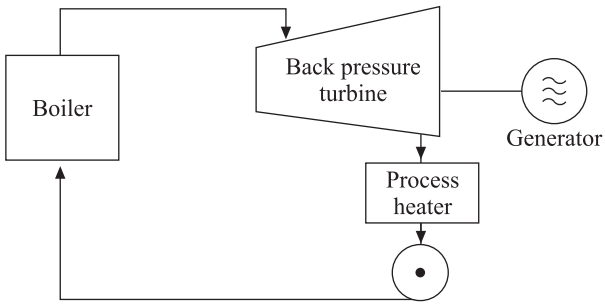


Figure 1.27 Cogeneration plant with a back pressure turbine.

1.7.2 Pass-Out Turbine

In case more power is required than generated by back pressure turbine, design of a pass-out turbine may help. In pass-out turbine, certain quantity of steam is extracted continuously at an intermediate stage for heating purposes. The regular exhaust can have condenser route as usual. By this arrangement more power can be produced in addition to meeting the demand of process steam. One such arrangement is shown in Figure 1.28.

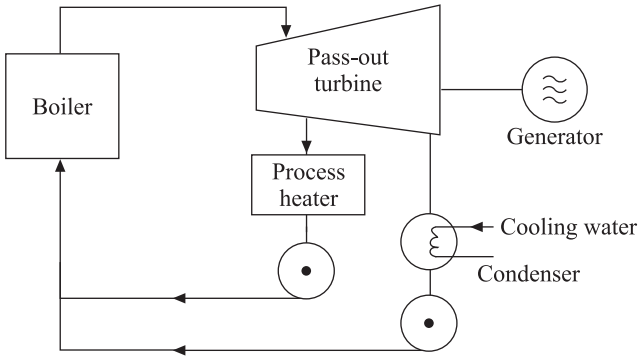


Figure 1.28 Cogeneration plant with a pass-out turbine.

1.7.3 Process Heat Unit

In factories like cement plants, the primary heat is utilized for regular processes. The waste heat coming out is then used for generating electricity. The efficiency of power generation may be low, but the overall efficiency may improve. It can be tried only when the cost of electricity generated is comparable to that purchased from a utility system.

Many industries operate regular thermal power station to meet their entire or partial requirement. Such a unit is called *captive power plant*. It will give freedom to operate their units at full capacity instead of depending on the general utility systems like state-owned electricity boards.

1.8 CONTROL ROOMS

In a thermal power plant the sensors and transmitters are mounted in the field and signals are transmitted through cables to the control room located in a central place for the convenience of operation. The incoming signals are processed and utilized for indicating, recording, integrating and storing. In addition, they are processed for controlling purposes either through different controllers or through a central process computer. The controller output signal is sent back to the field where the final control element is located. Annunciation system for alarming and tripping with audio-visual provision is made in the control room. The control room will normally be divided into three parts

1. Front panels
2. Rear panels
3. Engineer's cabin

1. **Front panels:** It will be installed in such a way that the operator concerned will be able to observe the various parameters through indicators, recorders, video display units etc. Annunciation acceptance switches, tripping and emergency switches are arranged for easy accessibility of the operator.
2. **Rear panels:** This will accommodate cable terminal blocks, control switches, control relays, power supplies etc. which are normally not to be observed. They are only occasionally inspected, maintained and kept in proper working condition.

3. **Engineer's cabin:** Provision in the control room is made for the engineer-in-charge of the plant to view the operations of the whole plant in a central display. He is also provided with facilities to interfere with the operating control parameters and change them for efficient operation of the plant. The operators are denied such independence.

In a steam thermal power plant, the control room is divided into two parts, namely, thermal or boiler control room and electrical control room. Many a times they are located separately. Thermal control room is located in the vicinity of boilers whereas the electrical control room is located in-between turbo alternator floor and transmission sub-station. Boiler control room activities are normally managed by mechanical engineers and the electrical control room activities by electrical engineers. Process control and automation engineers will have roles to play in both the control rooms.

1.8.1 Thermal or Boiler Control Room

A steam thermal power plant will have a group of boilers in operation. Front panels arrangement will be done to accommodate important boiler parameters like steam generation (steam flow), steam pressure, superheated steam temperature, feed water flow and drum water level. Indicators as well as recorders will be provided for such important parameters. Other parameters like fuel rate, air flow (primary and secondary), combustion air pressure, furnace draft, chimney draft, water circuit and air-flue gas-waste gas circuit temperatures and pressures will be displayed through indicators and/or indicators with selector switches. Auto/manual stations for different control loops with valve position indicators will be installed in such a location where operator's hand is easily reachable. One operator may observe and control one or two boilers at a time.

Either single loop or multi loop controllers will be used for controlling various controlled variables like drum water level, combustion air/fuel flow, superheated steam temperature etc. Video display units (VDU) are employed to view the overall operation of the boilers. Process operator control (POC) with engineer's keyboard will be accessed only by the engineer-in-charge to change/modify the controller settings. Back panels will be occupied by relays, contactors, protection switches etc. necessary for boiler controls.

The boiler control room will also accommodate some of the turbo-alternator instruments. They include steam pressure, temperature and flow to the turbine, casing and bearing temperatures, condensate level, vacuum and flow rate, speed of the turbine, power generated by individual alternators and total power. Frequency of the power generated will also form a part of the thermal control room information. Mostly this control room activity is dominated by mechanical engineers followed by instrumentation and control engineers.

1.8.2 Electrical Control Room

Normally there will be as many number of turbo alternators as that of the number of boilers. Electrical control room may be an extension of thermal control room or located separately. The measurements related to turbine, alternator, transformer and switch gears and controls will be looked after from this control room. Front panels, rear panels and engineer's cabin arrangement will be almost similar to that of thermal control room. The station engineers of both the control rooms have to work together for effective power generation and distribution.

Turbine speed control, alternator cooling, frequency of generation and rest of the power systems will be looked after from here. The master load-sharing controller signal will emanate from here and travel to thermal control room to control the steam output of different boilers through master fuel controller.

The power station incharge will coordinate with both the control room in charges to run the thermal power station efficiently and qualitatively.

1.8.3 Plan of Control Rooms

For power stations of smaller capacity, both boiler and electrical control rooms can be combined. A model plan of such a control room is shown in Figure 1.29. Administration and communication desks are also included. Through glassed observation window one can see the overall activities going on inside the control room.

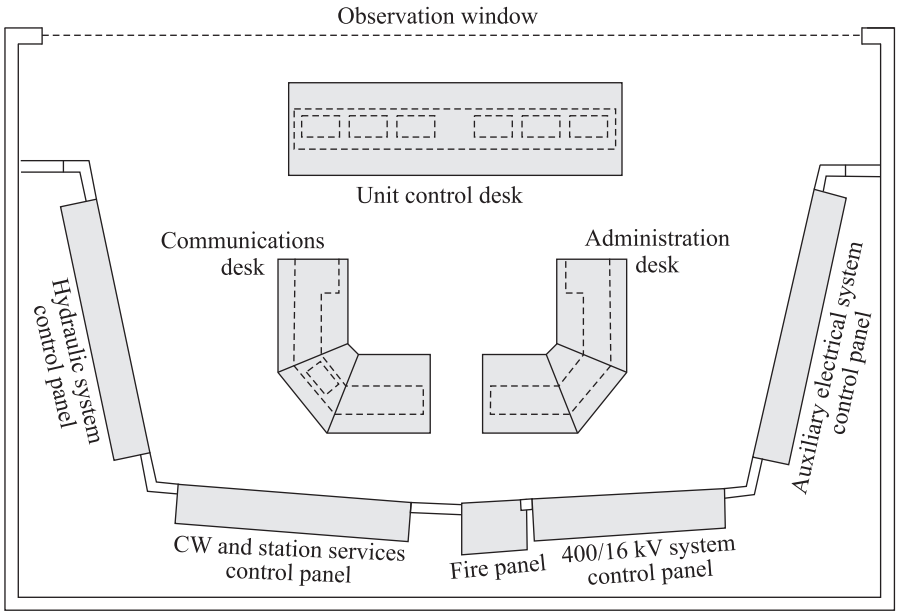


Figure 1.29 Plan of a control room.

Figure 1.30 shows the plan of a boiler control room of a power station with two boiler units. Backup control panels, auxiliary units and safety equipment are located by the side of the central control room. Figure 1.31 shows the plan of an electrical control room for the same power station. Figure 1.32 shows an alternate plan of an electrical control room with more infrastructure and communication facilities.

Figure 1.33 gives an idea of how one typical supervisor's desk would look like. Most of the equipment are concerned with communications. Considerable writing space is provided for documentation. Items of telecommunications equipment are often housed in the desk.

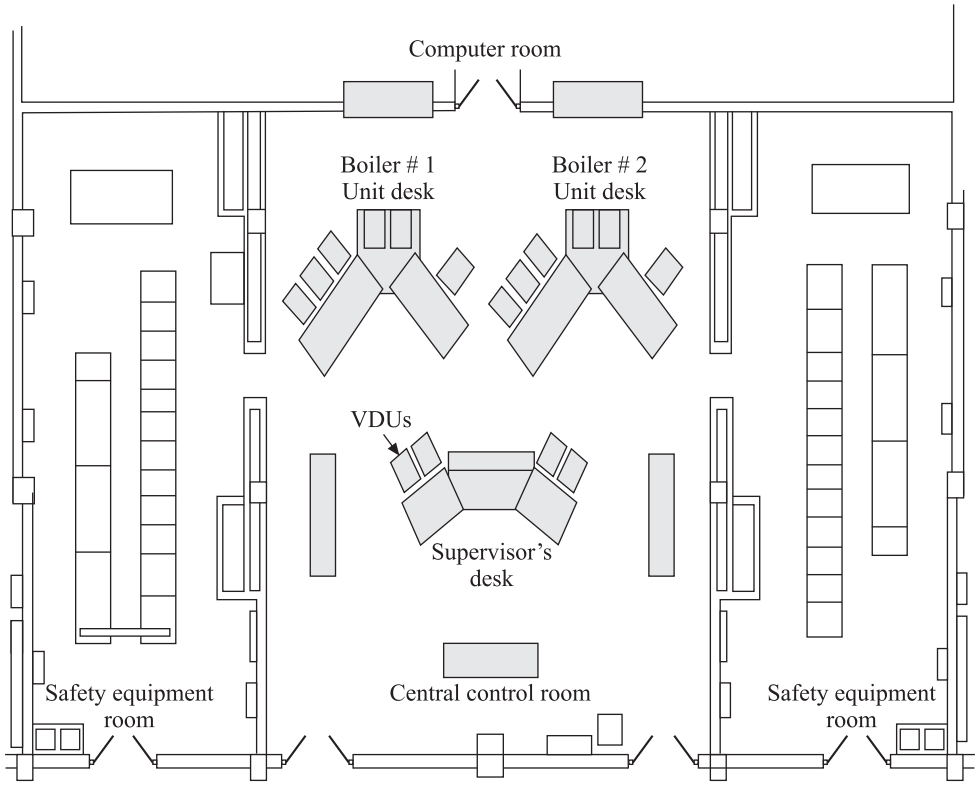


Figure 1.30 Plan of a boiler control room.

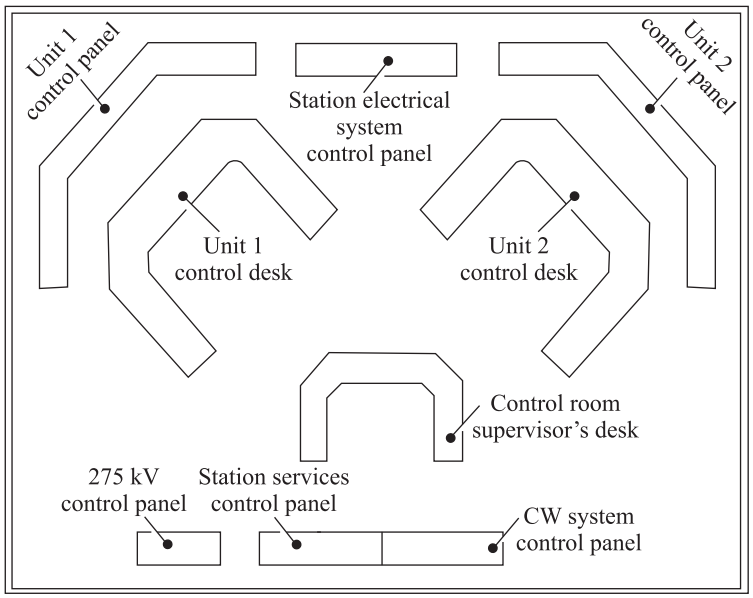


Figure 1.31 Plan of an electrical control room.

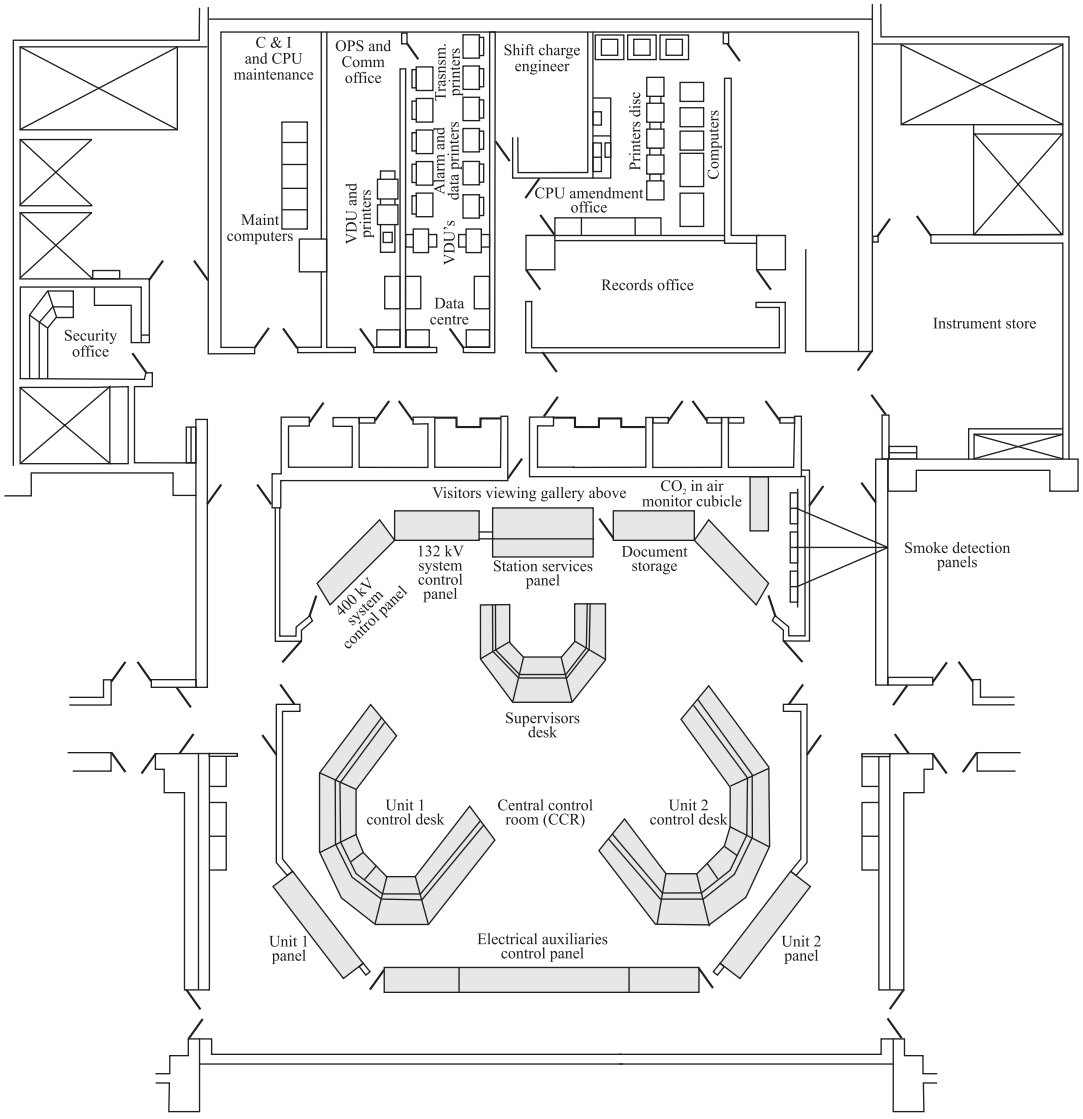


Figure 1.32 An alternate plan of an electrical control room.

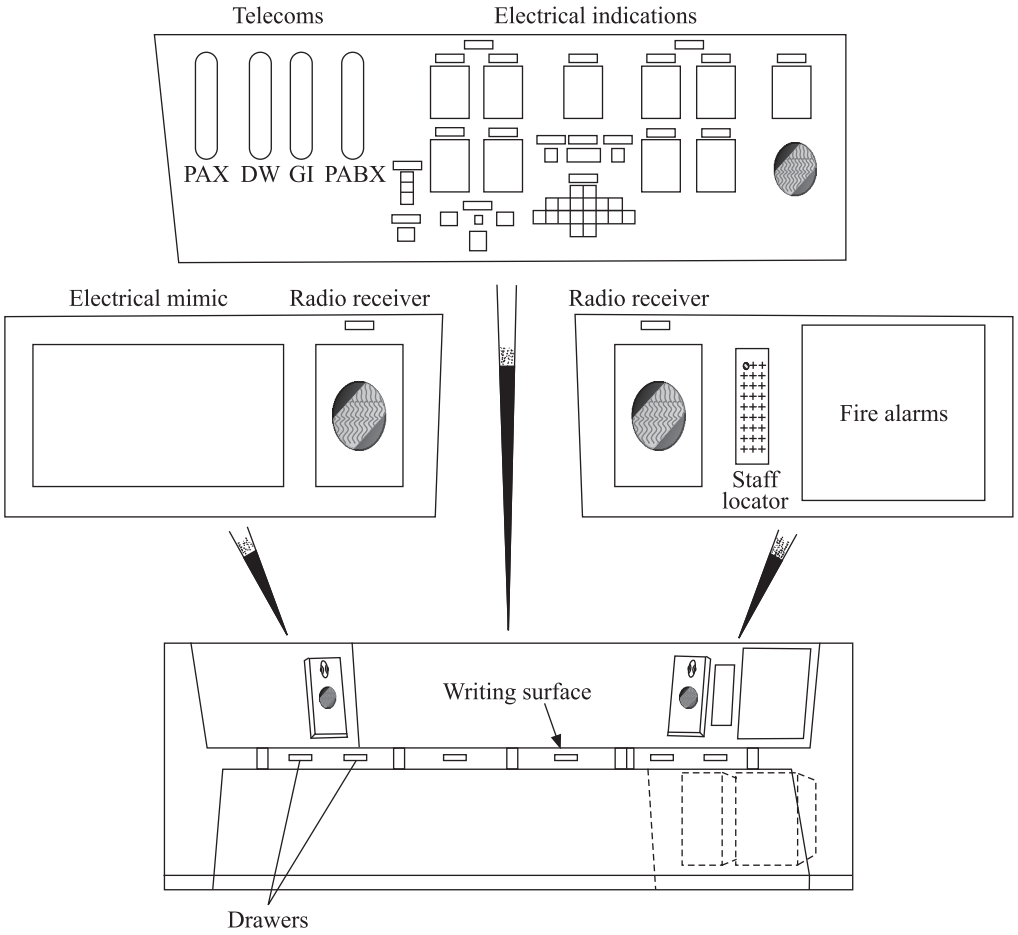


Figure 1.33 A typical control room supervisor's desk.

WORKED-OUT PROBLEMS

PROBLEM 1.1 Theoretically calculate the power that can be obtained from windmill with the following data. (Assume the density of air is 1.2 kg/m^3)

A = Swept area = 10 m^2
V = Wind velocity = 200 km/hr

Solution: The power developed by a windmill at the air density of 1.2 kg/m^3 is given by

$$P_D = 13.14 \times 10^{-6}\, AV^3$$

where

P_D = Power developed by the windmill in kW
A = Swept area in m^2
V = Wind velocity in km/hr.

$$\therefore \quad P_D = 13.14 \times 10^{-6} \times 10 \text{ m}^2 \times (200 \text{ km/hr})^3 \text{ kW}$$
$$= 1051.2 \text{ kW}$$
$$\simeq 1 \text{ MW}.$$

PROBLEM 1.2 Generators of 4 poles configuration and 8 poles configuration are available to be used with steam turbine and hydro turbine. Select the suitable generators after finding out their synchronous speeds.

Solution: The speed of the generator (N) to produce electricity at the grid frequency (f) 50 Hz is given by

$$N = \frac{120\, f}{P} \text{ rpm}$$

where P = Number of poles.
Speed of the generator with 8 poles

$$N_8 = \frac{120 \times 50}{8} = 750 \text{ rpm}$$

Speed of the generator with 4 poles

$$N_4 = \frac{120 \times 50}{4} = 1500 \text{ rpm}$$

We know that the efficiency of steam turbine is high at high speed whereas the efficiency of hydro turbine is high at low speed.

Hence the high speed generator (1500 rpm) with 4 poles can be coupled with steam turbine and the low speed one (750 rpm) with 8 poles may be coupled with hydro turbine.

PROBLEM 1.3 If a boiler consumes 100 T/hr feed water and delivers 96 T/hr steam throughout the day, calculate (i) average rate of blow down and (ii) total blow down for the day assuming that there is no other water loss in the system.

Solution: The steam output from the boiler is always less than the feed water input because of the water loss in the boiler system and the blowing down operation. Assuming water loss in the boiler system is nil, the less steam production is attributed only to blow down.

(i) Average rate of blow down = Feed water flow rate – steam flow rate
= 100 T/hr – 95 T/hr
= 5 T/hr.

(ii) Total blow down for the day = Average × 24 hrs
= 120 T

PROBLEM 1.4 Calculate the rate of makeup water to a boiler plant if the average feed water rate is 150 T/hr, the water loss in the boiler system including blow down is 3% of input and the steam loss in the turbine system is 2% of its input.

Solution: Feed water in = 150 T/hr

Steam out from boiler = $\left(150 - 150 \times \frac{3}{100}\right)$ T/hr = 145.5

Loss in the boiler system = 4.5 T/hr

∴ Steam into turbine = 145.5 T/hr.

Condensate water = $\left(145.5 - 145.5 \times \frac{2}{100}\right) = 142.59$ T/hr

Loss in the turbine = 2.91 T/hr.

Make-up water required = Feedwater required – Condensate water available

= 150 – 142.59

= 7.41 T/hr

or

Make-up water required = Water loss in boiler system + Steam loss in turbine system

= 4.5 + 2.91

= 7.41 T/hr

PROBLEM 1.5 Calculate the overall efficiency of a steam thermal power plant if,

Boiler efficiency = 82% = η_B

Turbine efficiency = 30% = η_T

Alternator efficiency = 95% = η_A

Solution: Overall efficiency of the thermal power plant

$$\eta = \eta_B \eta_T \eta_A$$

$$= \left(\frac{82\%}{100} \times \frac{30\%}{100} \times \frac{95\%}{100}\right) \times 100$$

$$= 23.37\%$$

EXERCISES

1. What are the major conventional sources of energy?
2. Name few non-conventional sources of energy
3. Differentiate between conventional and non-conventional sources of energy based on:
   (a) Environmental point of view
   (b) Availability
   (c) Economy.
4. If a two-pole electric generator and a four-pole electric generator are available for use in a steam thermal power plant, which one will be more preferred? What will be its synchronous speed at 50 Hz frequency?

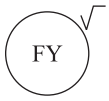
5. What are the essential components of a boiler?

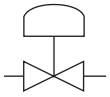
6. What is the role of control and instrumentation in power plants?

7. What for the following symbols are used?

(a)

(b)

(c) 

(d) 

8. How a nuclear reactor is controlled?

9. Name three different drafts in connection with boilers.

10. Name the fuels used in nuclear power plants.

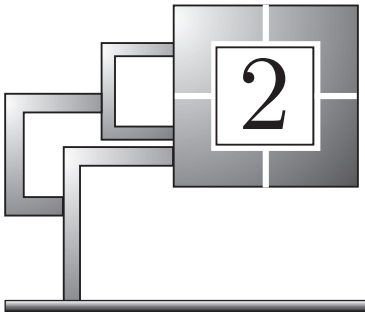
11. Explain the working of fast breeder reactor with sketch.

12. Calculate the average blow down for a boiler with 200 T/hr feed water, 5% and 3% losses in boiler system (other than blow down) and turbine system if the make-up water required is 20 T/hr.

13. What are the different turbines used in hydro stations?

14. Name four primary components of the core of a nuclear reactor.

15. What are the two signals used in a two element level controller?



Instrumentation and Control in Water Circuit

2.1 WATER CIRCUIT

A steam generator generates steam by heating water through burning fuel in its furnace. Generation of steam at the desired rate at the designed temperature and pressure is achieved with the help of lots of measurements and controls. Thereafter the steam power is used to rotate the prime mover, called *steam turbine*, and hence the electric generator to produce power. In this process, heat energy is converted into mechanical energy and then to electrical energy through turbine-generator system. The steam after driving the turbine is converted back into water by the condenser. The condensate water is fed into the feed water system to get added with makeup water and recirculated. Make up water is drawn from raw water after treatment. The condenser uses untreated cooling water for condensing purpose. Hence the water circuit in a thermal power plant can be divided into two circuits as we have already seen in Chapter 1 as below:

1. Feed water and steam flow circuit (Refer to Figure 1.21)
2. Cooling water flow circuit (Refer to Figure 1.22)

2.2 BOILER FEED WATER CIRCULATION

Circulation of feed water in the boiler plays a vital role in steam generation. If we consider a water tube boiler, the water tubes are normally connected between the boiler drum in the top and the tube header in the bottom. The water circulates within the tube, the drum and the header. The rate of steam formation is directly in relation to the water circulation rate. The circulation rate should be just adequate to remove the heat from tube surfaces. A sluggish circulation may cause large bubbles to form and hence the possibility of burning out tubes. The water movement is required to be always in one direction. Natural circulation by the gravity force, forced circulation by employing pumps or a combination of the two are generally employed.

2.2.1 Natural Circulation

The simple diagram shown in Figure 2.1 explains the natural circulation of boiler water. Heating the riser tubes with the help of hot flue gases causes the water to circulate and steam to be released in the boiler drum. The difference in density of the water in the down comer and the steam-water mixture in the riser circuit makes the water circulation possible. The water-steam mixture density is lower because of the heat absorbed in the riser. This lesser density saturated steam is delivered to the boiler drum. The combination of lesser density water in the downcomer creates the force required (due to gravity) to establish circulation. The ratio between the steam-water mixture flow into the drum and steam produced is called the *circulation ratio*. With increased heat input the circulation ratio and hence the steam output increase up to certain value. After that the increase in heat input will decrease the flow (Refer to Figure 2.2). Hence it is desirable to design the water circuit so that the operation point lies always in the region of rising part of the curve.

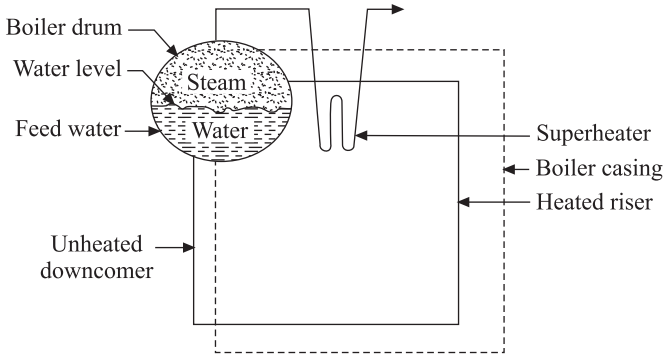


Figure 2.1 Natural water circulation.

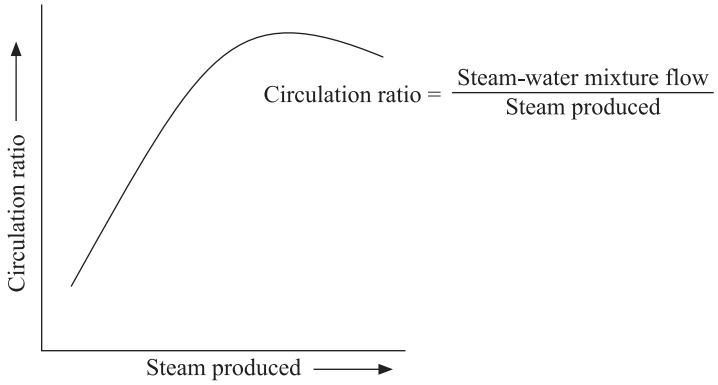


Figure 2.2 Steam versus circulation ratio.

2.2.2 Forced Circulation

Forced or positive circulation boilers utilize an external pump to force water or steam through the boiler circuits. One such system called *once through circulation* is shown in Figure 2.3.

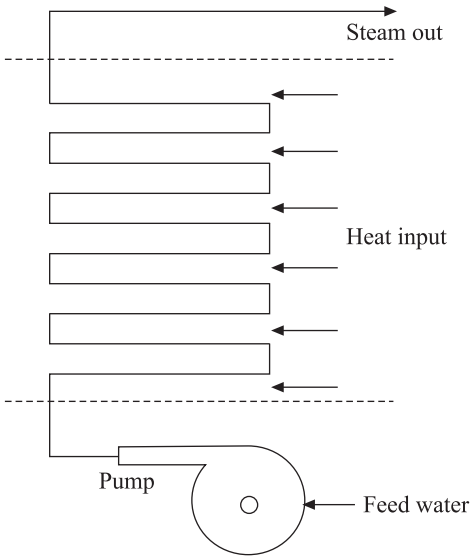


Figure 2.3 Forced (Once through) water circulation

2.2.3 Combined Circulation

The circulation of water in this case is done both by the force of gravity and by means of pump. Such a circulation system is shown in Figure 2.4.

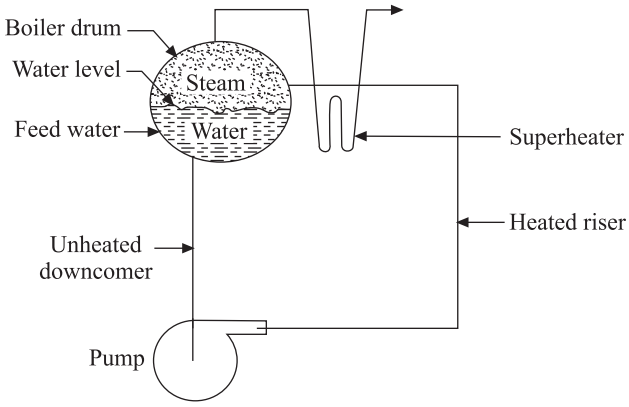


Figure 2.4 Combined water circulation.

Feed water supply

The feed water plays very important role in steam thermal power plant. The feed water is first converted into saturated steam in the combustion chamber area, then to superheated steam in the superheater. After the heat energy is utilized in the turbine to rotate turbo-alternator, the steam is condensed in the condenser and recirculated again as feed water. Physical condition of the feed water is measured at different points as pressure, temperature and quantity. The chemical condition

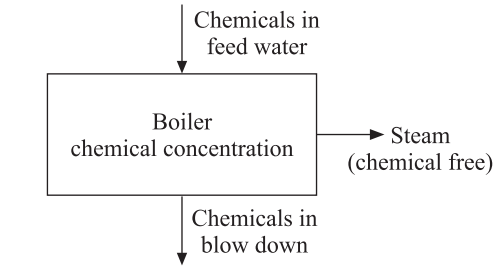
of the feed water is determined by measuring conductivity, pH, dissolved oxygen etc. The determination of chemical condition is more complex compared to the determination of physical condition. But knowing the chemical condition is also very important for the sake of safety and life of steam generators and turbines. It is rather impossible to have pure water from natural sources. Even potable waters supplied by the local bodies like corporation and municipality are not fit for continuous use as feed water. The waters involved in the boiler operation are named depending upon the source, location and application as below:

1. **Raw water:** It is natural water with such impurities as the earth has originally endowed it. Raw water is available either as 'ground water' or as 'surface water'.

   Ground water: The water available from wells and springs with dissolved hardness is usually clear.

   Surface water: The water from streams and lakes will have dissolved hardness like ground water in addition to insoluble organic and inorganic matter in suspension. Hence it is turbid.

   In general, natural waters need 'softening' for the removal of dissolved solids and 'clarification' for the removal of turbidity.
2. **Boiler water:** It is the actual liquid contents of the boiler, of which that in the water drum is typical.
3. **Feed water:** That water which is introduced into a boiler to replace the evaporation. The feed water has to be pumped by the feed water pump at a pressure sufficiently above that of the boiler to cause the correct flow into the boiler, that is, correct from the point of view of feed water demand under variable load operation. The feed water is passed through economizer to pick up some heat from the flue gases to increase the efficiency of operation.
4. **Blow down:** Water that is drained from the boiler. Depending on the point of blow down connection, this water may have equal or greater impurity content than the boiler water. In all boilers a proper chemical balance must be maintained. Figure 2.5 demonstrates the chemical balance.



$$\text{Blow down flow} = \frac{\text{Feed water flow}}{\text{Concentration ratio}}$$

Figure 2.5 Blow down and chemical balance.

The boiler steam scrubbers are intended to prevent any carry-over of boiler water chemical content into the steam. All chemicals that enter the boiler through injection or in the feed water must ultimately be removed in the boiler blow down. Assuming a constant level of chemical concentration in the boiler water and also in the feed water, the chemical

concentration of the water in the boiler is determined by the ratio of blow down flow to feed water flow. If the average blow down flow is 10 percent of feed water flow, then the chemical concentration of the boiler water is 10 times that of the feed water.

5. **Condensate water:** The steam generated from the boiler is utilized in the turbine for rotating it and hence the alternator for power generation. The exhaust steam from the turbine is condensed in the condenser with the help of circulating cooling water and collected in the hot well. The water thus collected, is reused as feed water so that no more treatment is required for this water.
6. **Make-up water:** The condensate water is not sufficient as feed water because some portion of feed water is lost in the process as loss of water in boiler system including blow down and loss of water in turbine system due to evaporation, leakages etc. To make up that, raw water has to be treated and added to the condensate water.

$$\text{Boiler feed water} = \text{Condensate water} + \text{Make up water}$$

On a continuous basis only the portion of boiler feed water called *make-up water* needs to be treated chemically.

7. **Cooling water:** To condense the steam in the condenser and maintain low pressure in it, a large quantity of cooling water is required. This water is taken from the river or pond, but not treated like boiler feed water. The heat absorbed by this water can be removed by sending this water to cooling tower. Then the same water can be recirculated. The scheme has already been discussed (Refer to Figure 1.22).

A typical boiler feed water supply consists of two parts, make up water treated in the water treatment plant and the condensate water. The feed water is heated and pumped by feed water pumps to the boiler. Figure 2.6 shows a general arrangement of a basic feed water supply system. The feed water is admitted to the deaerating heater where it is heated with a help of steam. While heating helps to improve boiler efficiency, the deaeration helps to remove the dissolved gases like oxygen and carbon dioxide.

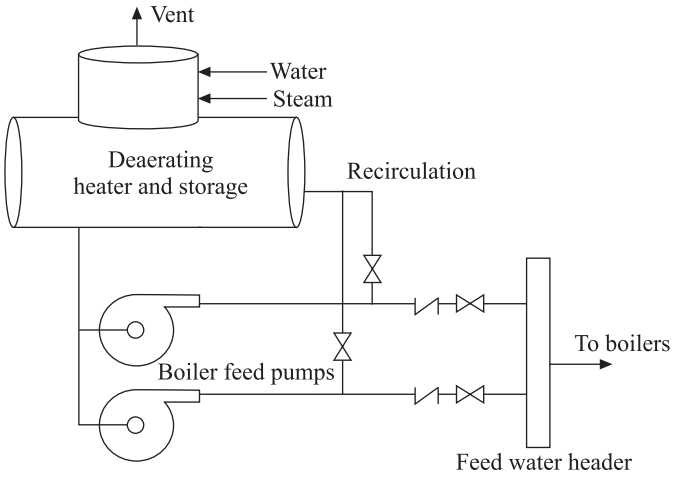


Figure 2.6 Basic feed water supply system.

Deaeration: It is highly recommended to eliminate the entrained or dissolved gases like oxygen and carbon dioxide from the feed water before entering the boiler. If carbon dioxide remains in the water, it will be carried along with steam and get converted into corrosive carbonic acid. Heat exchangers that use the steam and the steam-carrying pipelines will get corroded. The dissolved oxygen, if not removed, can corrode the boiler seriously. The process of elimination of such dissolved gases from the feed water before allowing it to the boiler is called 'deaeration'. Water can hold the dissolved gases in greater amounts at low temperature. Vigorous boiling and venting the gases to atmosphere helps remove the dissolved gases.

Water is directly heated with steam to form an intimate mixture of steam and water at boiling point. The entrained or dissolved gases get released from the water. The released gases are then vented out to atmosphere. The deaeration process eliminates them as efficiently as possible. The remaining traces of dissolved gases can be further removed by scavenging chemicals.

Coming back to the basic feed water supply system, the water leaving the deaerator heater is deposited into an integrated heated-water storage tank which is connected to the section of the boiler feed pumps. Shut off valves, non-return valves etc are shown in recirculation and feeding lines to have proper operation. With more than one pump connected, the check valve would be closed on any pump that is not in operation. In larger power plants, two feed water headers are put in operation to have uninterrupted feed water supply.

2.3 MEASUREMENTS IN WATER CIRCUIT

For maintaining the operation of the thermal power plant efficiently and uninterruptedly, it is very essential to have the stable water circulation system. Automatic controls such as boiler drum level control (feed water control), superheated steam temperature control, steam bus pressure control, steam flow control (turbine speed control) etc. are to be put in position. For all the above controls, the measurement of controlled variable and manipulated variable are essential. The following measurements are considered appropriate for the above purpose.

1. Water flow measurement of raw water, make up water, condensate water, feed water and cooling water.
2. Steam flow measurement at various points.
3. Pressure measurements of steam, water etc. at various points.
4. Temperature measurement of water and steam at various points.
5. Level measurement in boiler drum and deaerator.

We will discuss briefly about the above measurements applied to thermal power plant before getting deep into automatic controls.

2.3.1 Water Flow Measurement

The common methods of measurements of water flows in thermal power plant are by using differential pressure head sensors such as orifice and venturimeter. We may also encounter in an average power plant the rotary displacement meter, V-notch meter, turbine meter, etc. We will restrict our discussions only to differential head sensors and connected transducers (head flow

meters). The operating principle is that a reduction of pressure accompanies an increase of velocity (Bernoulli's theorem). The velocity is increased by inserting a fitting (orifice or venturimeter etc.) which converges to a minimum section and then diverges to the normal pipe size. With proper design of the sensors one can arrive at the following relation between flow rate (Q) and the differential pressure developed across the sensor (h)

$$Q = K\sqrt{h}$$

where

Q = Water flow rate in m^3 /hr or T/hr

h = Differential pressure head in mmwg

K = Sensor constant

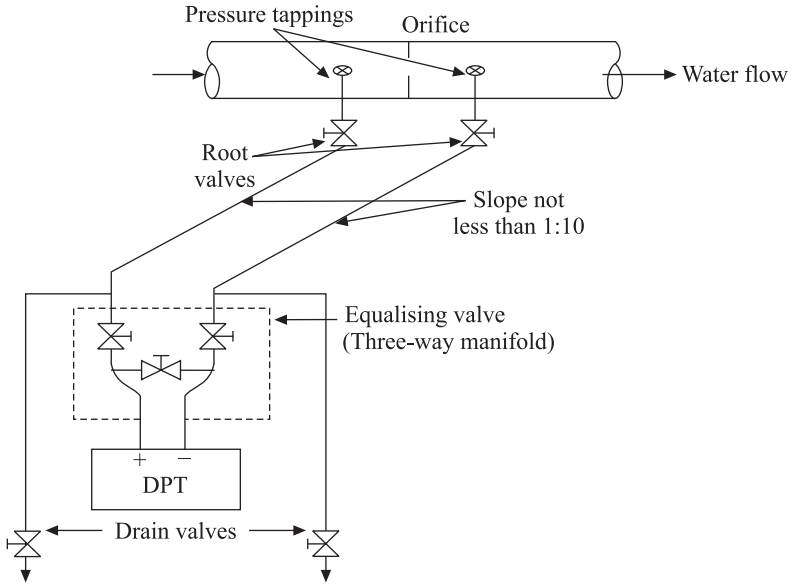
The installation details to be discussed below will be same for all water flow measurements in a thermal plant, such as feed water, raw water, make up water, condensate water, injection water, etc. Only the flow range, location of the sensor, etc. will vary as required for a particular water flow measurement.

Installation of head flow meters

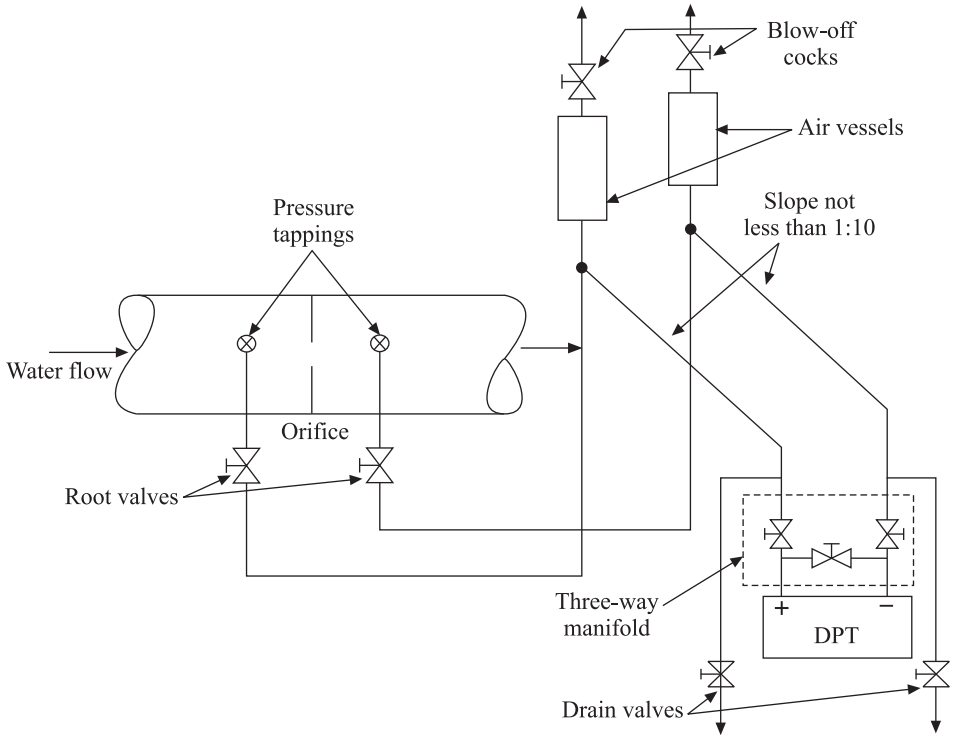
Primary elements of the head flow meter are an orifice, venturi, dall tube or pitot tube, and a differential pressure transmitter which are used to measure the differential head caused by the flowing water at the primary element. The differential-pressure transmitter and the primary element need utmost care at the time of connection and installation. It is very important to note that the meter is used for the purpose of measuring differential pressure. Any extraneous or false head used by the connecting piping may cause a serious error.

Pressure piping is the pipe which connects the pipe tapings of the head producers to the differential pressure transmitters (DPTs). The important point to be carefully considered in laying the pressure piping in order to avoid false readings is the air or vapour locking. If the transmitter is to be located below the water pipeline, the pressure pipeline should be laid at a slope of not less than 1/10 [Refer to Figure 2.7(a)]. If the horizontal distance is too long to allow this slope by direct connection between the head producer (say orifice) and the transmitter, then pressure pipes may be first taken below, risen above and then to the transmitter [Refer to Figures 2.7(b)]. If the transmitter is to be located above the water pipeline, the pressure pipe is first laid vertically downwards to a distance of about 0.5 m in order to minimize the possibility of entrance of air or gas from the main, and the pipe is raised continuously at a slope of not less than 1/10 to the transmitter. Figures 2.7(a), (b), and 2.8 illustrate such installations.

It is also very important that certain minimum straight runs of the main pipe before and after the restriction (orifice) be provided. As a thumb rule, a straight run of about five diameters of the main pipe is adequate. Elbows, valves, protection tubes, etc. are to be avoided in this straight run to permit the steady water flow in the vicinity of orifice.



(a) Pressure pipeline (I).



(b) Pressure pipeline (II).

Figures 2.7(a) and (b) Pressure connections to DPT below orifice.

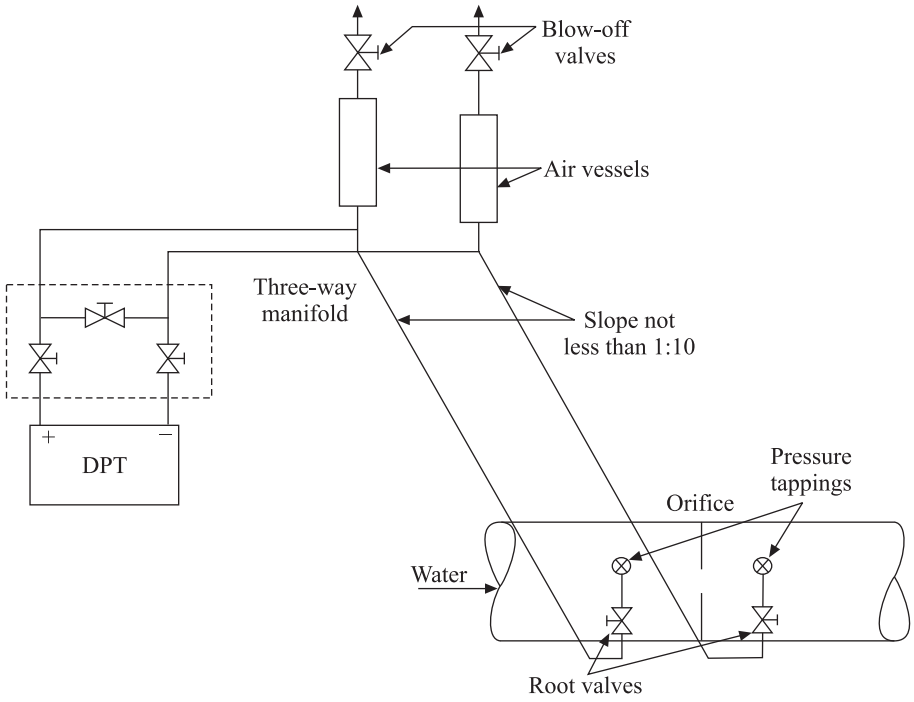


Figure 2.8 Pressure connections to DPT above orifice.

2.3.2 Differential Pressure Transmitter (DPT)

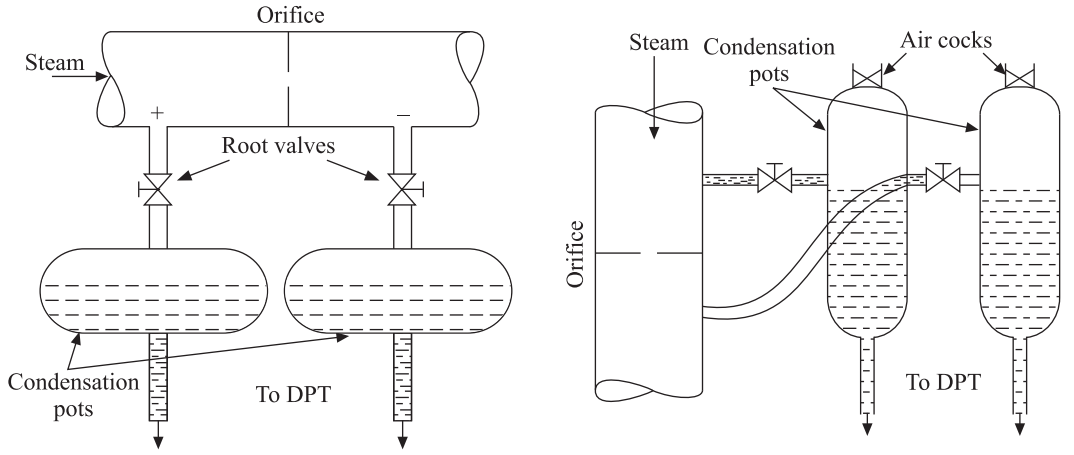
DPT outputs a 4–20 mA DC signal corresponding to the measured differential pressure. As the flow-head relation is non-linear $(Q = K\sqrt{h})$, it is necessary to make the current of the transmitter linear to flow rate. For this purpose a square root extractor (whether built-in or externally added) is used. DPT normally requires a DC voltage of 12 V to 42 V and connected to various other circuits using two wires only. They are called *two-wire transmitters*. Improved versions of such transmitters are called *smart transmitters* with computer compatibility.

2.3.3 Steam Flow Measurement

Steam flow measurements are done to know the steam generated by the individual boilers, total steam generated by the plant, steam consumed by the turbines and other process steam requirements. The method used for steam flow measurement is almost same as that used for water flow measurement. The pressure piping here will contain condensate. Condensate chambers or pots should be connected to the pressure taps of adequate size to supply enough condensate and to ensure equally high columns above the flow meter. Any excess condensate will drain back to the pipeline.

Condensation pots

Typical installations of condensation pots for both horizontal steamline and vertical steamline are shown in Figures 2.9(a) and (b).



(a) Condensation pots – horizontal pipe (b) Condensation pots – vertical steam pipe

Figure 2.9 Installation of condensation pots.

In case of vertical steamlines, it is essential that both the condensation pots placed at the level of the upper orifice connection. Condensation pots are manufactured with different metals to suit the various pressure ranges. The different metals used are cast iron (up to 16 kg/cm^2), carbon steel (up to 64 kg/cm^2), stainless steel (from 64 to 100 kg/cm^2) and molybdenum steel (for pressures above 100 kg/cm^2 up to 200 kg/cm^2).

Temperature and pressure corrections

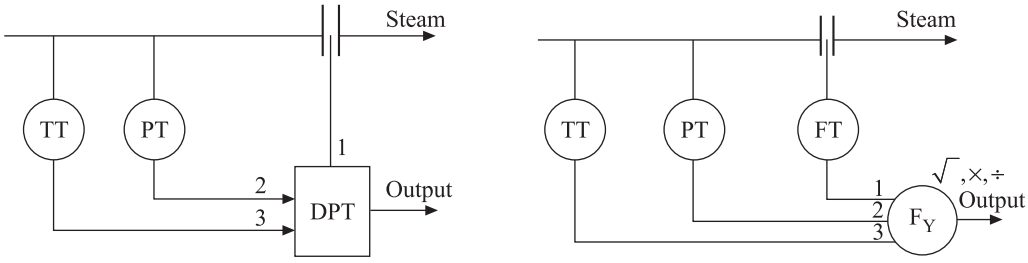
The density of steam is a function of both temperature and pressure. Measuring errors can occur if the density in operation differs appreciably from the design figures of the restriction (say orifice). In that event a correction has to be introduced. The correction factor for steam when measured in Tons/hr unit is given as $CF = \sqrt{\frac{\rho_O}{\rho_D}} = \sqrt{\frac{P_O T_D}{P_D T_O}}$ where ρ_O, P_O and T_O are operating density, pressure and temperature, and ρ_D, P_D and T_D are corresponding design values.

The correction computation can be built in as an integral part of DPT or separately done as shown in Figure 2.10.

Input 1 : Differential head from orifice (h)
Input 2 : Pressure (P_O)
Input 3 : Temperature (T_O)

$$\text{Output} = K\sqrt{h \times \frac{P_O}{T_O}}$$

Scaling and biasing are also necessary to get a standard electrical 4–20 mA signal corresponding to flow range. The input signals are also standard 4–20 mA signals for the corresponding differential head range, pressure range and temperature range. The design temperature and pressure are taken into constant K factor.



(a) Built-in computation. (b) Computation by a separate unit.

Figure 2.10 Pressure and temperature correction for steam flow measurement.

2.3.4 Water and Steam Pressure Measurements

Pressure measurements are required at various points in water and steamlines. For local indications Bourdon tube pressure gauges are normally used. Direct piping is used as pressure lines to connect the gauge from main line for cooling water and water with less temperature. For hot water and steam mains the Bourdon gauges are to be connected with pressure gauge bends to avoid direct steam or hot water contact with Bourdon tube as shown in Figure 2.11.

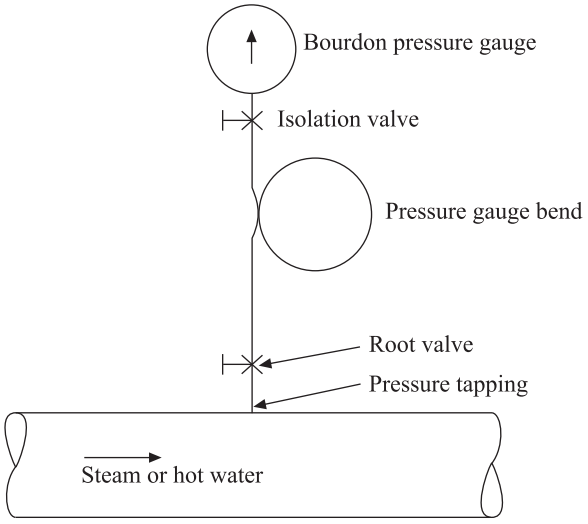


Figure 2.11 Installation of bourdon gauge with bend.

For transmitting type pressure measurements, electronic transmitters with standard 4–20 mA output are used. The sensing elements used may vary from strain gauge, capacitive type, potentiometric type, inductive type to linear variable differential transformer (LVDT) type. The sensors used will normally depend on the range and location. Very high pressures are measured with piston type pressure gauges and bulk modulus cell pressure transmitters. Smart transmitters are used widely nowadays to have self-calibration and span adjustment facility.

Operating pressures and temperatures for pressure pipes, valves and fittings are specified in different standards. The temperature of water and steam varies from room temperature for cooling water to around 600ºC for superheated steam. The pressure variations can be expected from about 2 kg/cm^2 (raw water) to about 100 kg/cm^2 (boiler feed water).

Measurement of pressure is carried out to know the pressures of water and steam at various points in boiler and turbo alternator. Sometimes it is done for pressure correction purposes for steam flow measurement.

Steam bus pressure measurement

It is very important to measure precisely, the steam pressure in the common steam bus of a steam thermal plant where a number of boilers are in operation and the steam generated by them are connected to a common bus before being distributed to turbo alternators. This measurement is done with zero suppression and expansion of the scale at operating pressure so that this signal can be given to master fuel controller for boiler load sharing purposes.

Figure 2.12 shows a piston type pressure gauge which is highly accurate and suitable for bus pressure measurement. The steam acts upon a piston located in an oil-filled pressure cell.

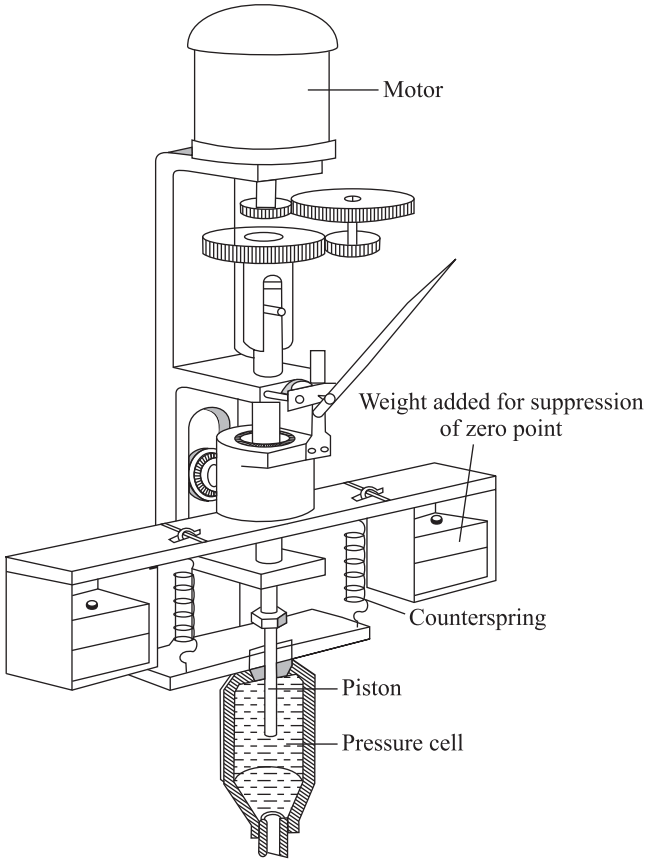


Figure 2.12 Diagram of piston-type pressure gauge.

To reduce friction to a minimum, a small electric motor rotates the piston slowly and permanently. The counterforce is supplied by two helical springs. To suppress the zero point, the piston is preloaded by weights. The reading is displayed locally on a large-size dial and transmitted through several types of transmitters. The stroke of the piston is transmitted to the local pointer and the various transmitters by means of rack and pinion to suit a linear pressure characteristic. The range may be ± 10% of the operating pressure. For the operating pressure of 100 kg/cm^2, the range of this meter will be 90 to 110 kg/cm^2 .

2.3.5 Water and Steam Temperature Measurements

Water temperatures

The temperatures of different waters in the boiler system are necessarily to be measured. The different points are cooling water in and out of condenser, raw water, make up water, condensate water, feed water before and after economizer, feed water before and after deaerator and feed water inlet to boiler drum.

The normal range of the water temperature is 0 to 100°C and hence contact type resistance thermometer detectors (RTDs) are used as sensors. Though platinum thermometers are used maximum, nickel and copper thermometers are also used in limited locations. The commercial name for platinum thermometer is Pt100, specifying the resistance at 0ºC as 100 Ω. Liquid in glass (Mercury in glass) thermometers are used for local indications.

Steam temperatures: The temperatures of steam at the following points are very important for controlling the boiler operation—drum steam temperature, steam temperatures before and after superheaters, boiler outlet steam temperatures, common bus temperature and turbine inlet temperatures. The range at different points may vary from about 200°C to about 600°C. Though RTDs can be used for low temperature ranges, iron–constantan thermocouples are universally used for this range.

Installation of temperature sensors: As we have seen, the temperature of water and steam varies to a maximum of about 600°C. The pressure in those pipes vary from about 2.5 kg/cm^2 (raw water line) to about 100 kg/cm^2 in feed water line. Superheated steam temperature and pressure are about 550°C and 60 kg/cm^2. Hence protection is required for the temperature sensors to operate with such temperature and pressure. Suitable protection tubes and fixing methods are to be adopted. Screwing the sensor on the pipeline with protection tubes for low pressure lines and direct welding for high pressure lines are recommended.

Figure 2.13 shows the commercial types of electrical contact thermometers (RTDs and thermocouples with protection tubes) used for water and steam temperatures measurement.

2.3.6 Drum Water Level Measurement

This is one of the very important and critical measurements in a boiler. Both local and remote indications of boiler level are always attempted.

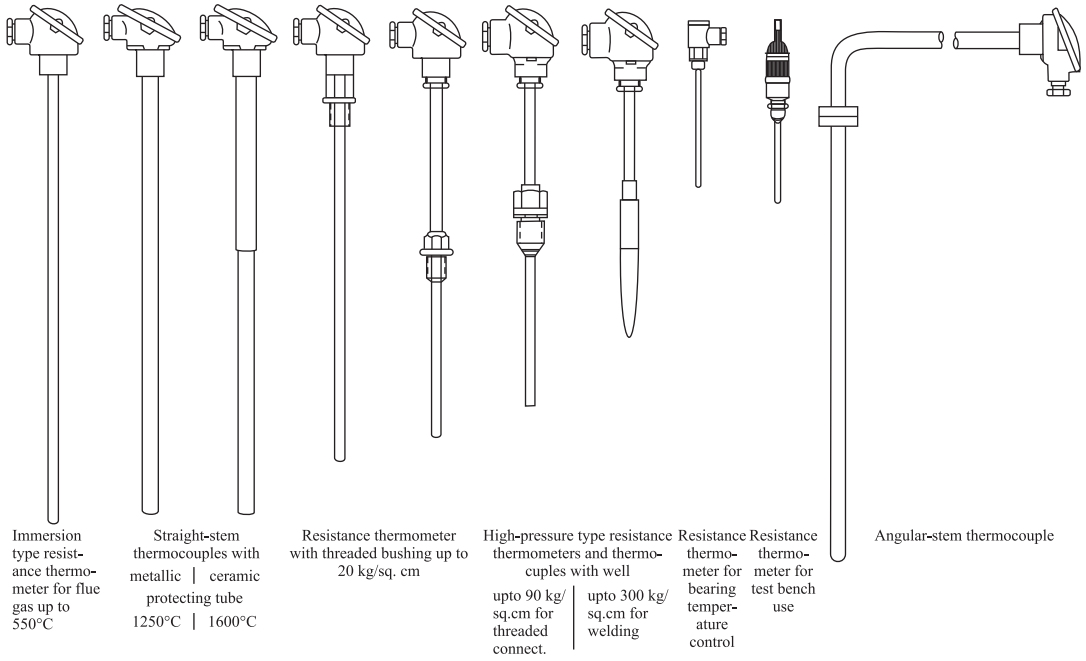

Immersion type resistance thermometer for flue gas up to 550°C
Straight-stem thermocouples with
metallic | ceramic
protecting tube
1250°C | 1600°C
Resistance thermometer with threaded bushing up to 20 kg/sq. cm
High-pressure type resistance thermometers and thermocuples with well
upto 90 kg/sq.cm for threaded connect.
upto 300 kg/sq.cm for welding
Resistance thermometer for bearing temperature control
Resistance thermometer for test bench use
Angular-stem thermocouple

Figure 2.13 Commercial types of electrical contact thermometers.

Local indication

The basic indication of the drum water level is that shown in a sight gage glass connected to the boiler drum. The typical arrangement is shown in Figure 2.14.

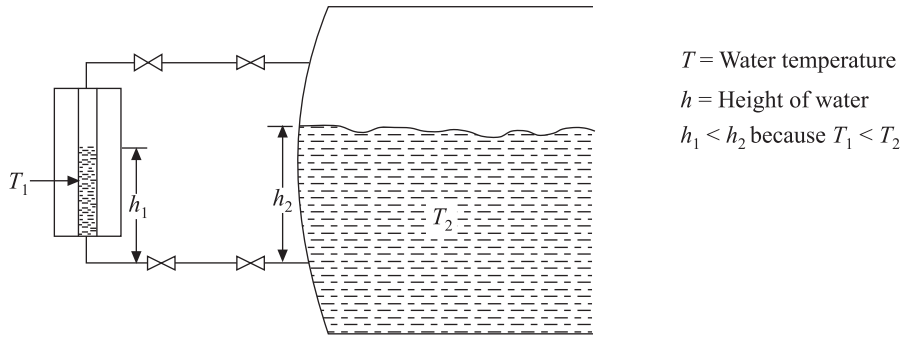


Figure 2.14 Gage glass drum level indication.

Since the configuration of the boiler and the distance of the boiler drum from the operator may not provide a useful 'line-of-sight' indication, the gage glass image is usually projected with a periscope arrangement of mirrors so that the operator may easily view it. In modern power plants, closed circuit television is used as shown in Figure 2.15 to display the gage glass level in a monitor in the control room.

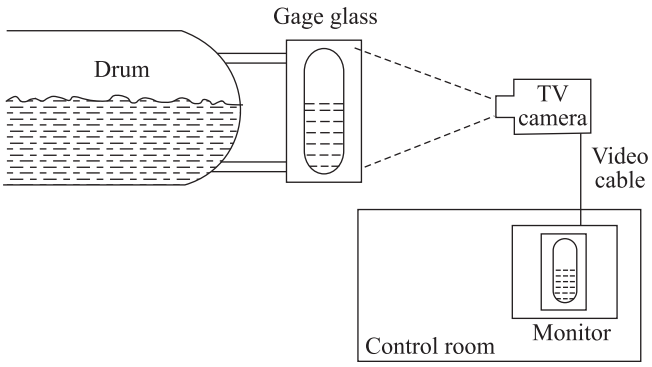


Figure 2.15 Drum level observation using CCTV.

Because of the temperature difference between the water in the drum and the water in the gage glass, the level shown by the gage glass is always lesser. The deviation depends also on the boiler pressure, piping and insulation between the boiler drum and the gage glass.

Drum level transmitter

A typical arrangement of a drum level measuring transmitter is shown in Figure 2.16. The transmitter is a differential pressure device in which the output signal increases as the differential pressure decreases. This is because of the decrease in differential pressure for increase in water level. Typically the differential pressure range is approximately 60 cms with a zero suppression

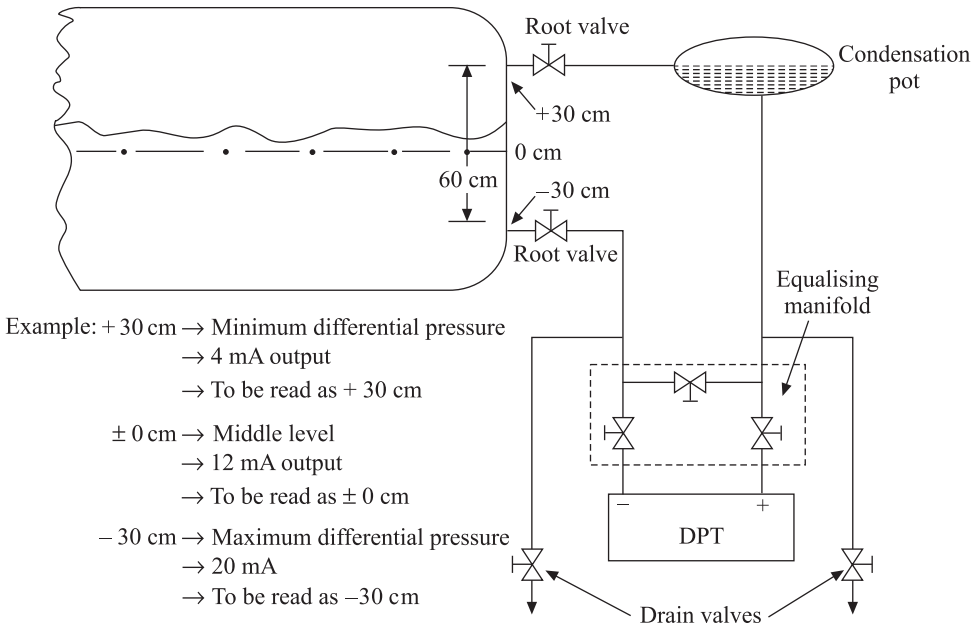


Figure 2.16 Drum level transmitter.

of several cms. To determine the measuring instrument calibration, the necessary design data are the location of the upper and lower pressure taps into the boiler drum with respect to the normal water level, the operating pressure of the boiler drum, and the ambient temperature around the external piping. With these data and the desired range span of the transmitter, the exact calibration can be calculated by using the standard thermo dynamic properties of steam and water.

On the high-pressure side of the transmitter, the effective pressure equals boiler drum pressure plus the weight of a water column at ambient temperature having a length equal to the distance between the two drum pressure connections. On the low-pressure side, the effective pressure equals boiler drum pressure, plus the weight of a column of saturated steam having a length from the upper drum pressure connection to the water level, plus the weight of the column of water at saturation temperature having a length from the water level to the lower drum pressure connection.

Shrinking and swelling

A typical cross section of a boiler drum is shown in Figure 2.17. We have already seen the boiler water circulation system in the beginning of this chapter. Feed water at lesser temperature compared to the saturated steam/water enters the drum. Because of the temperature difference, an increase in feed water flow causes the water bubbles collapse to some extent. It also decelerates the formation of bubbles in the tubes temporarily. Hence one observes the fall in liquid level apparently though the mass of liquid content in the drum increased because of increase in feed water supply. Such a phenomenon in drum level measurement is called '*shrinking*'. One can observe similar phenomenon when steam pressure in the drum increases because of sudden decrease in steam drawn out from the drum.

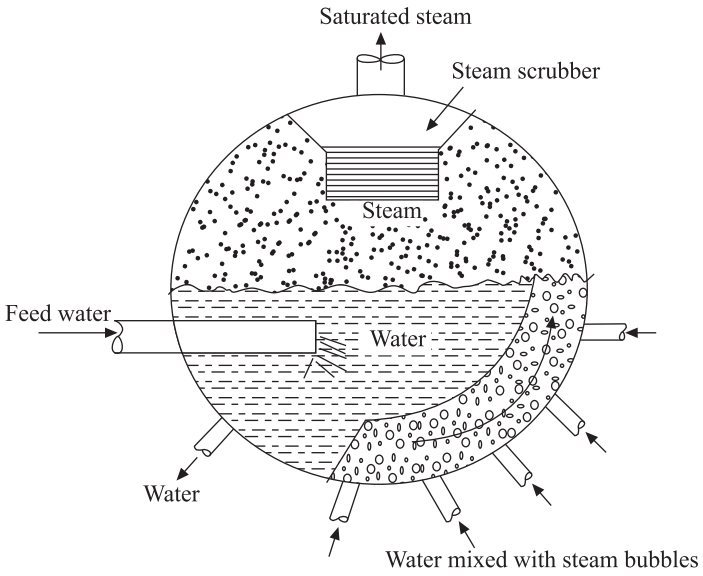


Figure 2.17 Boiler drum.

Whenever the feed water supply to the boiler drum is reduced suddenly, the rate of collapse of bubbles gets reduced and hence the apparent level increases. Also when steam drawn from the drum is increased to match the increase in load, the bubbles cause the water level to rise rather than fall because of the more mass drawn from the drum. This phenomenon is called *swelling* which can be seen as complimentary to shrinking.

Drum pressure compensation

Since the differential pressure transmitter measures differential pressure, the boiler drum pressure cancels out, leaving only the water column pressure difference. Since the density of saturated steam and water at saturated temperature changes as drum pressure changes, the level calibration data will be correct only at a single boiler drum pressure. The signal from the measuring transmitter can be pressure compensated to be correct for all pressures by providing a drum pressure measurement and using it to multiply and bias the basic drum level measurement signal.

Let us consider a simplified diagram of drum level measurement as shown in Figure 2.18, to derive the equations required for drum pressure compensation.

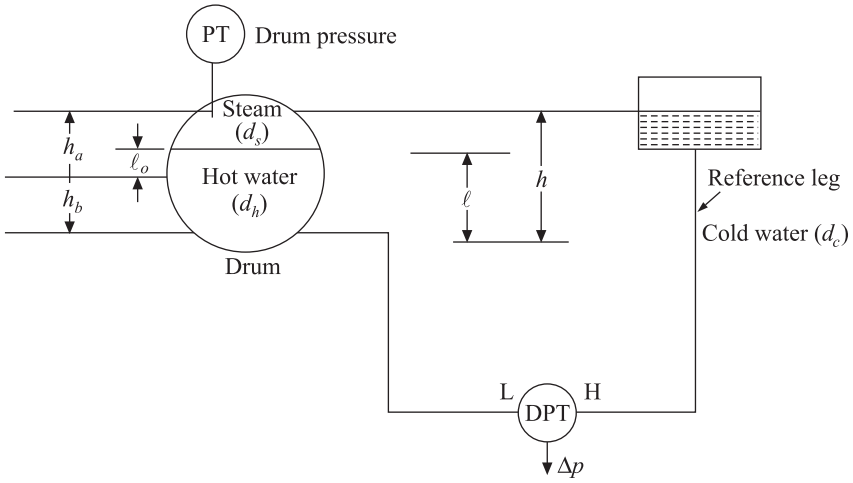


Figure 2.18 Drum level measurement.

Let d_s, d_h and d_c are densities of steam, drum hot water and reference leg's cold water. The densities of steam and hot water are the characterised functions of pressure based on data available in the steam tables. The reference leg data is treated as a constant and is also determined from steam table data using the actual temperature of the reference leg and normal operating pressure conditions.

$$\begin{aligned}\Delta P &= h\,d_c - d_h - (h -)\,d_s \\ &= h\,d_c - (d_h - d_s) - hd_s \\ &= -[\Delta P + hd_s - hd_c]/d_h - d_s \\ &= \frac{hd_c - hd_s - \Delta P}{d_h - d_s}\end{aligned} \tag{2.1}$$

$$\ell = \ell_o + h_b$$

$$\ell_o = \ell - h_b$$

$$\ell_o = \frac{hd_c - hd_s - \Delta P}{d_h - d_s} - h_b \tag{2.2}$$

The functional block diagram involved to get the compensated drum level is shown in Figure 2.19 which is self-explanatory.

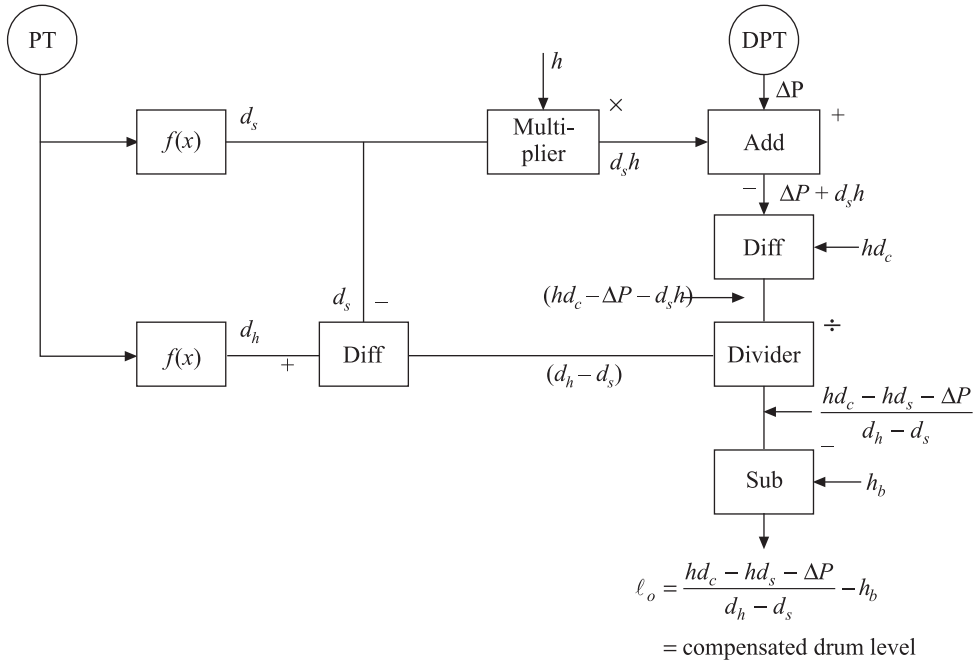


Figure 2.19 Drum pressure compensation for drum level.

The differential pressure transmitter is exhibited with the bottom tap connected with the low-pressure connection while the top tap is connected with the high-pressure connection through the filled reference leg. This kind of connection arrangement gives an output signal that varies inversely with level. With this kind of arrangement, it must be observed that the pressure at the high-pressure connection will always be more than or equal to the pressure at the low-pressure connection. This causes a differential pressure range that varies from *h* to *o* cms of water. Some of the users may prefer reversing these connections so that the output signal varies directly with level. It will result in a differential pressure range which varies from –*h* to *o* cms of water.

2.4 CONTROLS IN WATER CIRCUIT

The basic objectives of boiler controls can be divided into four major ones as described below:

1. **Increase uptime and availability:** To cause the boiler to provide a continuous supply of steam at the desired condition of pressure and temperature. Many power plants may

have more than one boiler running in parallel. It is essential to maintain and upgrade the boiler control systems to assure steam availability. Modern controls are more reliable and can readily adjust to load swings caused by varying overall plant operations.

2. **Reduce flue gas emissions:** Failure to comply with current emissions regulations can be as costly as lost utilities. Improved combustion efficiency through controls reduces unwanted combustion by-products. By accurately controlling oxygen (air), fuel flow, and stack temperature, reductions in plant emissions can be achieved.
3. **Maintain boiler safety:** A modern control system will provide tight integration with the flame safety or burner management system to improve safety. Having access to field data, diagnostics, and alarms, coupled with modern electronic controls can achieve the desired level of safety and security.
4. **Control operating costs:** A modern boiler control system will facilitate controlling operation costs in the following ways.
   (a) It Improves combustion efficiency to reduce fuel consumption by reducing excess air.
   (b) It provides a flexible control strategy to reduce or eliminate process upsets.
   (c) It readily makes data available for remote monitoring to determine process unit optimization, boiler efficiency, and load allocation
   (d) It reduces engineering, installation and start-up costs
   (e) It reduces maintenance costs associated with obsolete equipment.

   Keeping the above basic objectives in mind and knowing the necessity of independent controls, the control strategy has to be worked out. In this section we will discuss about the following control systems connected with water circuit.

1. Boiler drum level control
2. Superheated steam temperature control
3. Bus steam pressure control.

2.4.1 Boiler Drum Level Control

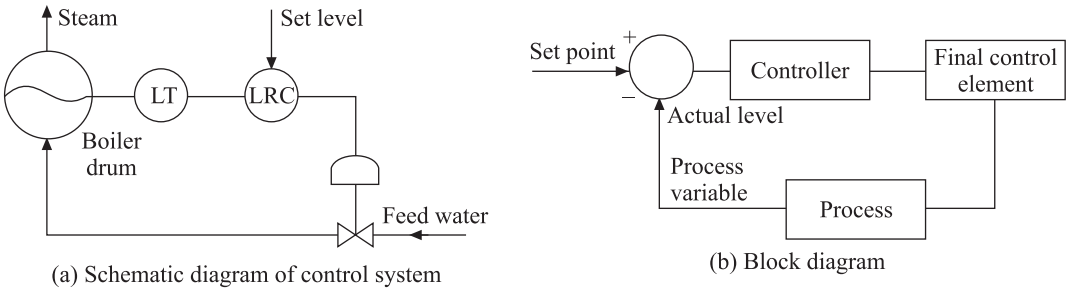
Boiler drum level is a critical process variable for the safe operation of a boiler and to some extent the turbine. The low drum level may cause uncovering of water tubes which in turn expose the tubes to heat stress and finally, damage them. High drum level means the water carried over to the steam header and turbine. Water particles in steam may become a reason for exposing steam turbines to corrosion and damage. An increased level may also interfere with the moisture separation device of the drum. Overflowing may even cause water entering into turbines resulting in major damages. The inverse response transients such as 'shrink' and 'swell' complicate the level control actions. This may cause severe control system overshoot or undershoot, though it is only temporary.

The boiler drum level control is expected to meet the following objectives.

1. It maximizes steam quality.
2. It prevents damage to boiler and turbine.
3. Balance the boiler steam output with the feed water input.
4. Compensate for feed water pressure variation.

Single-element drum level control

The single-element system is the simplest type used for controlling packaged fire tube or water tube boilers. In this strategy, control is based on the boiler drum level measurement only. This does not allow for compensation of any shrink or swell and, therefore is only an acceptable control strategy for small boilers with slow load changes. A simple proportional control with level as process variable will do. Integral action here is avoided because of 'swell' action in the boiler drum. Control of this type therefore involves addition of feed water on straight proportional level control. Figure 2.20 shows such a control system.



(a) Schematic diagram of control system

(b) Block diagram

Figure 2.20 Single-element feedback control for drum level.

Level signal is directly compared with set point and the error through controller is utilized for actuating the feed water control valve. Since only level signal is utilized, this is called *single-element control*. The control action of such a simple feedback control system (with single-element) for a change in steam flow (load) is shown in Figure 2.21.

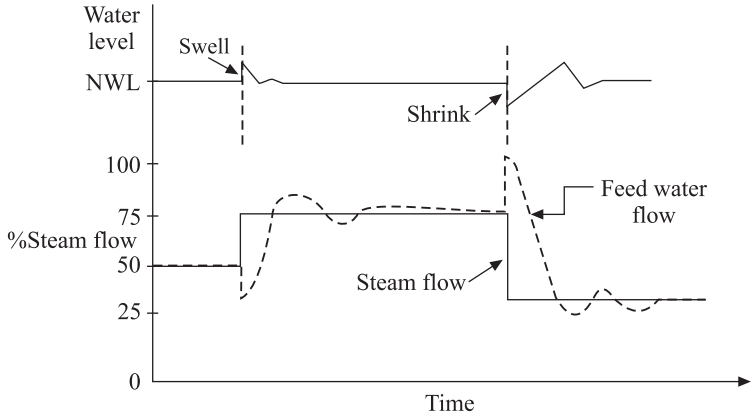


Figure 2.21 Control action of single-element level control.

Two-element drum level control

Two-element control is normally used for intermediate size boilers. Small boilers may also require such a system if they are expected to undergo rapid, frequent and large magnitude load changes. For medium size boilers, two element control is preferred when single-element control is not enough to take care of 'shrink' and 'swell' problems. Even for large boilers this control can be adopted provided the relationship between feed water control valve position and flow rate is consistent.

Outlet steam flow rate is measured as second signal in addition to drum level and used in the control system. It becomes second element in the control loop. Feed forward-plus-feedback control is employed with steam flow as feed forward signal. Variations in steam flow start making variations in feed water valve, thus trying to correct the anticipated level variations even before the level changes. Feed water control valve is required to be adjusted to match the feed water valve position and hence the feed water flow (not used) to the steam flow. Level offset is caused if mismatching is allowed. Figure 2.22 shows one such two element feed forward-plus-feedback control system.

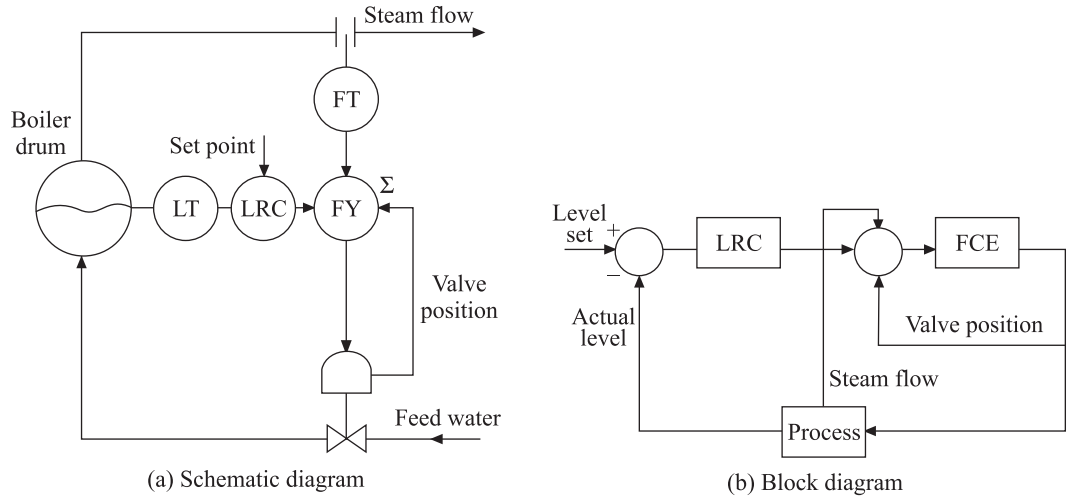


Figure 2.22 Two element feed forward-feedback control for drum level.

To take care of shrink and swell actions, proper tuning is required matching the effects of steam flow and drum level. Figure 2.23 shows how the control performance is affected by variations in feed water pressure. Such variations will change the relationship between steam flow and feed water flow. Under these conditions there is a definite possibility of an offset from set point. Three element feed water control is necessary under such circumstances.

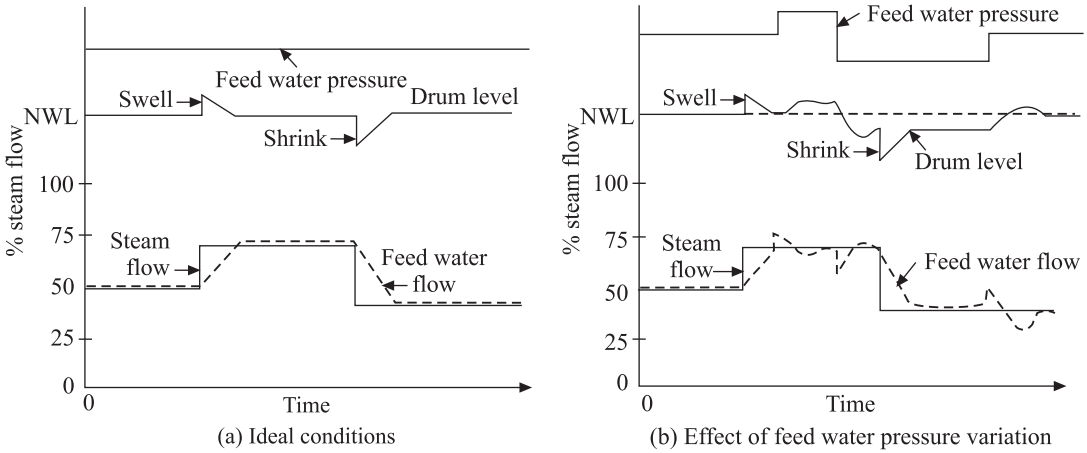


Figure 2.23 Performance of two-element drum level control.

Three-element drum level control

Feed water flow signal is added to the control in addition to water level and steam flow signals of two element control. Steam flow measurement helps to have feed forward signal which will try to keep feed water supply in balance with steam load demand. Unavoidable errors in flow measurements and other process load disturbances are corrected and trimmed in the level controller to the level set point finally. Three element control is suitable for large boilers which experience fast and wide load changes. Reduction of drum size and increase in velocities in the water and steam system are possible with three-element control. Thus economic consideration here is also taken care of.

Feed forward-plus-feedback cascade control is the most commonly used system with three-element level control. Figure 2.24 and Figure 2.25 show two alternate ways of hooking up the control system whereas Figure 2.26 shows a general control system block diagram.

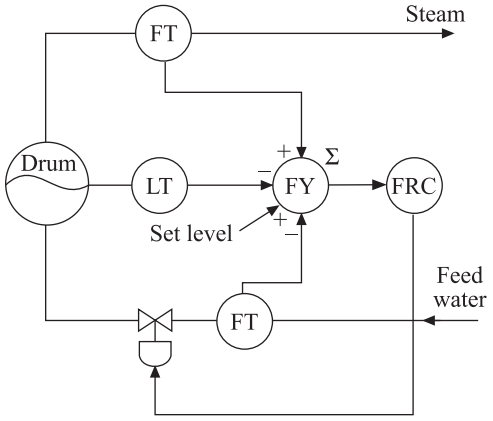


Figure 2.24 Three-element drum level control-Alternate 1.

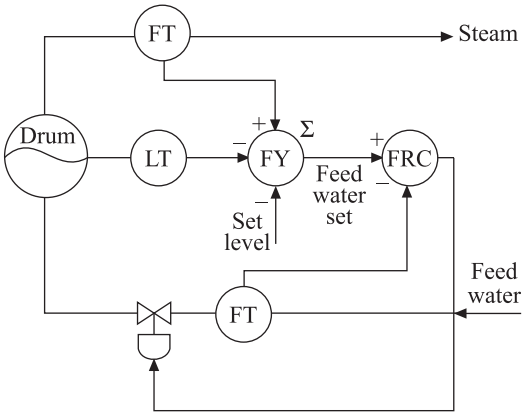


Figure 2.25 Three-element drum level control-Alternate 2.

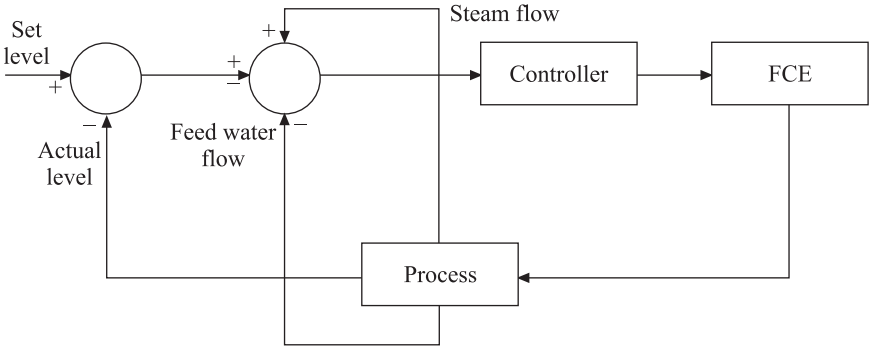


Figure 2.26 Three-element drum level control block diagram.

Compared to two element control system, the feed water flow loop is closed one here instead of open one. In simple control terms, drum level set point and actual level are compared, the difference (error) is added/subtracted with steam flow and the resultant becomes set point for feed water flow. When the actual level matches with set point, if there is demand for more steam, the steam flow increases and hence water flow increases. This happens even before any level change is sensed in drum for want of more steam demand.

An alternate control strategy is shown in Figure 2.27 where steam flow signal acts as set point to feed water flow controller. The output of that controller is given as additional signal to feed back level controller. The level controller output signal finally, actuates the control valve in the feed water line.

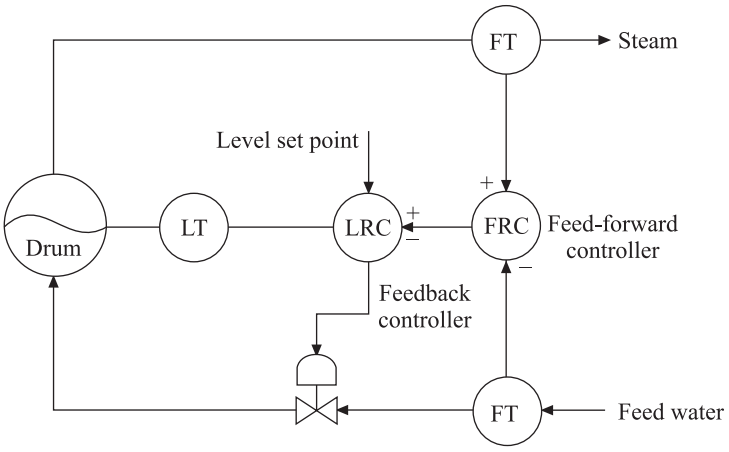


Figure 2.27 Three-element level control -Alternate 3.

It is expected that at steady state, feed water flow is equal to the steam flow and the level remains at set value. Change in feed water flow or steam flow due to various plant conditions is recognised in anticipation and action taken much before the disturbance causes the level change. The offset which is likely to occur is taken care of by the feedback controller as it takes actual level also into account.

The use of feedback in a feed forward system does not detract from the performance improvement which was gained by feed forward control. Without feed forward the feedback control loop was required to change its output follow all changes in load. With feed forward the feedback controller must only change its output by an amount equal to what the feed forward system fails to correct.

The tuning of the feed water control loop would be typical of a flow control loop. In making gain adjustment on a three-element feed water system, the first step is to determine the relative gain between level and flow loops. By observing a change in boiler load one can note the particular boiler 'swell' characteristics. Maximum system stability results when the negative effect of swell equals the positive effect of flow. Properly tuned, the performance of the three-element control should appear approximately as shown in Figure 2.28.

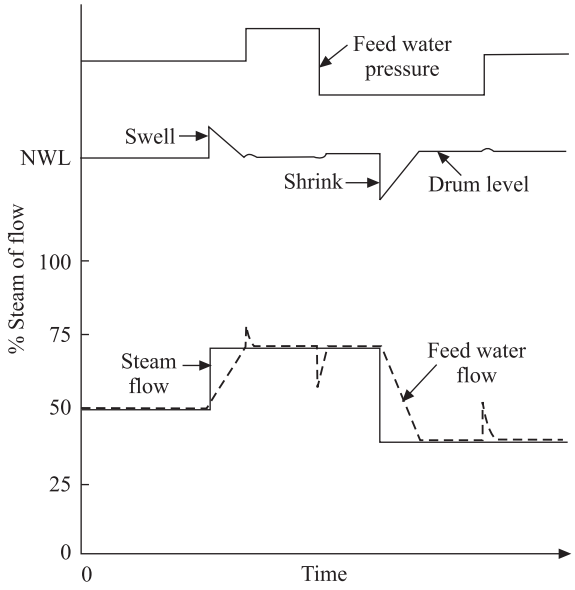


Figure 2.28 Performance of three-element feed water control.

Combined single-element and three-element drum level control

During startup or low load operation, the flow measurements used in the three-element control strategy may fall well below the rangeability limits of these flow metres. In that situation, three-element drum level control becomes erratic, and it is better to control the drum level with a single-element control strategy.

As shown in Figure 2.29, drum level control switches automatically from three element to single-element when steam flow falls below an adjustable low limit. Separate level controllers are used to allow different controller tuning for single-element versus three-element control and to provide appropriate controller tracking strategies to provide for bumpless transfer between these two control modes.

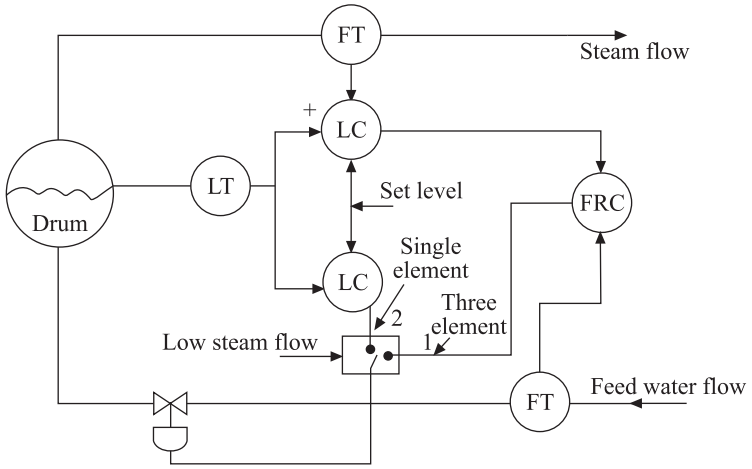


Figure 2.29 Combined single and three-element drum level control.

2.4.2 Superheated Steam Temperature Control

Superheaters

Heating of steam further from saturation temperature is called *superheating*. Dry superheated steam is required for proper turbine operation. Work is done in the turbine by the superheated steam till condensation begins. Superheaters are bundles of tubes located in the path of combustion gases where higher temperature is expected. Saturated steam from the boiler is passed through superheaters where the heat energy from combustion gases is added to it so as to generate superheated steam.

Superheaters are classified as convection superheaters and radiation superheaters depending upon how they receive heat energy. Heat energy is received directly by convection process in case of convection superheaters. They are installed in the path of hot gases. Radiation superheaters are exposed to the radiant heat of the furnace wall. The steam temperature versus firing rate characteristics of these superheaters are opposite in nature as shown in Figure 2.30. In case of radiant superheaters, the temperature of the steam decreases as steam output increases. This phenomenon is because of the relatively constant radiant energy. In case of convection super-heaters, the heat energy available is almost proportional to the steam load. The combustion process is controlled with load demand as the primary signal. Hence the heat transferred rises as steam flow increases. The rate of increase may become less as the steam flow increases continuously. Combining of both convection and radiant superheaters in series one may achieve less temperature changes as steam load increases. 'Platen superheaters' and 'Interdeck superheaters' absorb heat by both convection and radiation processes.

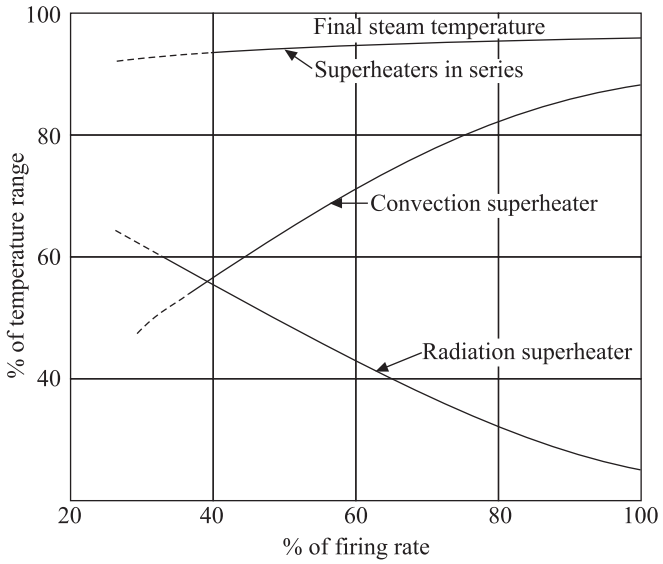


Figure 2.30 Superheater characteristics.

Steam temperature control

It is very essential to maintain the temperature of the superheated steam coming out of the boiler and utilized in the turbine for efficient and safe operation of the turbo-alternator. It helps in the

economy of conversion of heat energy into mechanical energy in the turbine. Constant temperature operation also helps to minimize the unequal expansion or contraction in the mechanical parts. Hence a steam temperature control system is called for to maintain the outlet steam temperature of the boiler at all boiler loads. Variations in the electrical load and hence the boiler load, fuel quality, burner design and its angle, excess air, feed water temperature, blow down quantity, bleed steam quantity and surface conditions of heat transfer components are some of the factors that contribute to the superheated steam temperature variations.

The steam temperature control mechanisms may involve either the water side or the fire side of the boiler. The water side control strategies are:

1. Spraying cold water using desuperheater.
2. By diverting part of the steam away from superheater section and cooling it with the help of shell-and-tube heat exchanger called *attemperator*.
3. By diverting part of the feed water through attemperator for condensing partially the saturated boiler steam.

The fire side control mechanisms operate by changing either the temperature or quantity of flue gases entering the superheater. The different fire side control strategies are:

1. Excess air control
2. Flue gas bypass control
3. Adjustable burner control/burners tilting control.

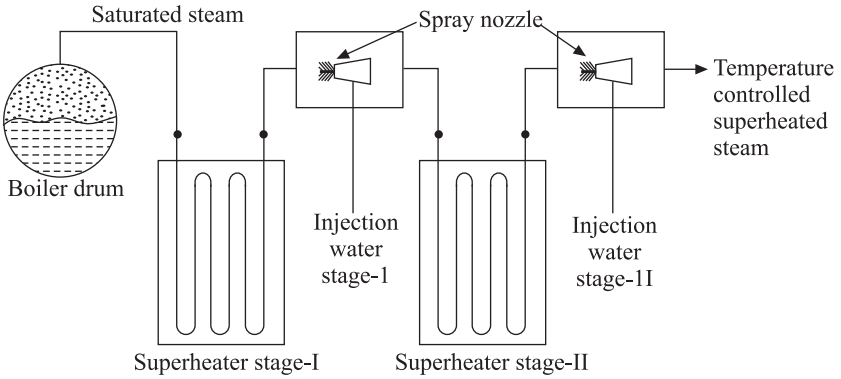
Out of all, the most commonly used method of superheated steam temperature control is through water side and that too by spraying cold water using desuperheater.

Water side steam temperature control

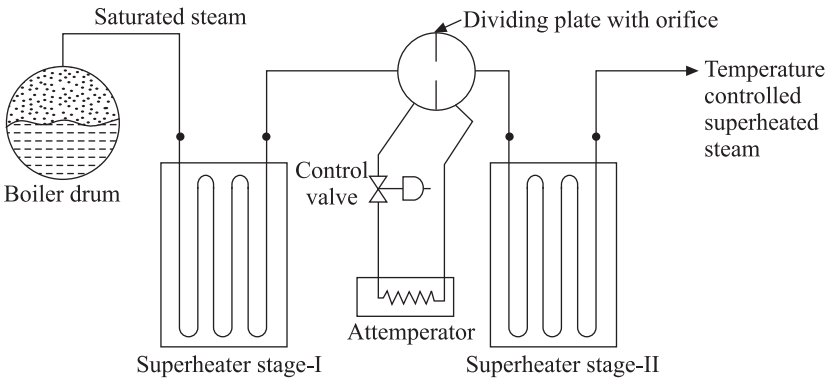
Desuperheater action is just the reverse of superheater action. The temperature and heat content of steam is reduced here unlike the superheater which increases the temperature and heat content of steam. Desuperheater may be located either between two successive sections of the superheaters or at the superheater outlet. Contact type or spray type ones are called *desuperheaters* and the non-contact shell type ones are sometimes called *attemperators*.

1. **Desuperheater-spraying cold water:** A separate line is drawn from the main feed water pipe before it enters economiser. The water flowing through this separate line is sometimes called *injection water*. Injection water flow is the manipulated variable for controlling the temperature, the process variable. Final control elements are installed in this line to regulate the amount of spray water as per demand. The injected water joins the main steam flow and evaporates. By absorbing latent heat of steam the injection water cools the steam. By varying the amount of injection water, the steam temperature control can be made possible. Figure 2.31(a) shows such a system with two stages of superheater and desuperheater.
2. **Attemperator: Diverting part of the steam:** Part of the superheated steam is diverted with the help of dividing plate with orifice and a control valve in the diverted line. The diverted steam is passed through an attemperator, shell-and-tube heat exchanger, before mixing up with the main steam. The diverted steam flow becomes manipulated variable. One such scheme is shown in Figure 2.31(b).

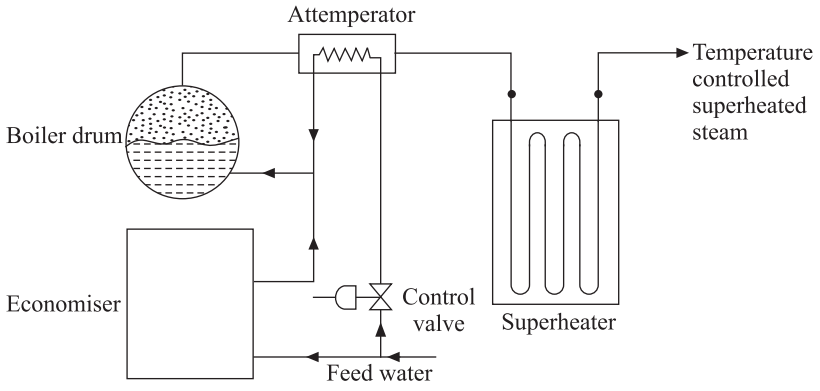
3. **Attemperator: Diverting part of the feed water:** Part of the feed water is diverted to an attemperator (a shell-and-tube heat exchanger) to remove variable amount of the latent heat and control the final steam temperature. The outlet feed water from the attemperator joins back the main feed water coming out of economizer and before entering the boiler drum. Figure 2.31(c) shows schematically the working of such a system.



(a) Temperature control–spraying cold water



(b) Attemperator–Diverting part of the steam



(c) Attemperator–Diverting part of the feed water

Figure 2.31 Water side steam temperature controls.

The temperature control from water side is more responsive. Single-stage control and two-stage control are possible. Single stage is a simple feedback controller with final temperature after desuperheater as controlled variable and injection spray water flow as manipulated variable [Refer to Figure 2.32]

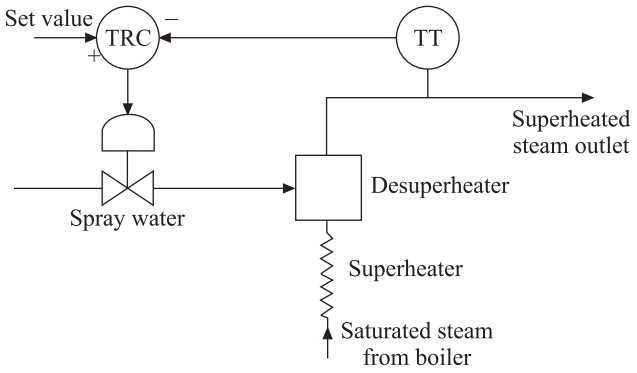


Figure 2.32 Single-stage steam temperature control.

A two-stage control will have two independent controllers in series and the controlling strategy is shown in Figure 2.33.

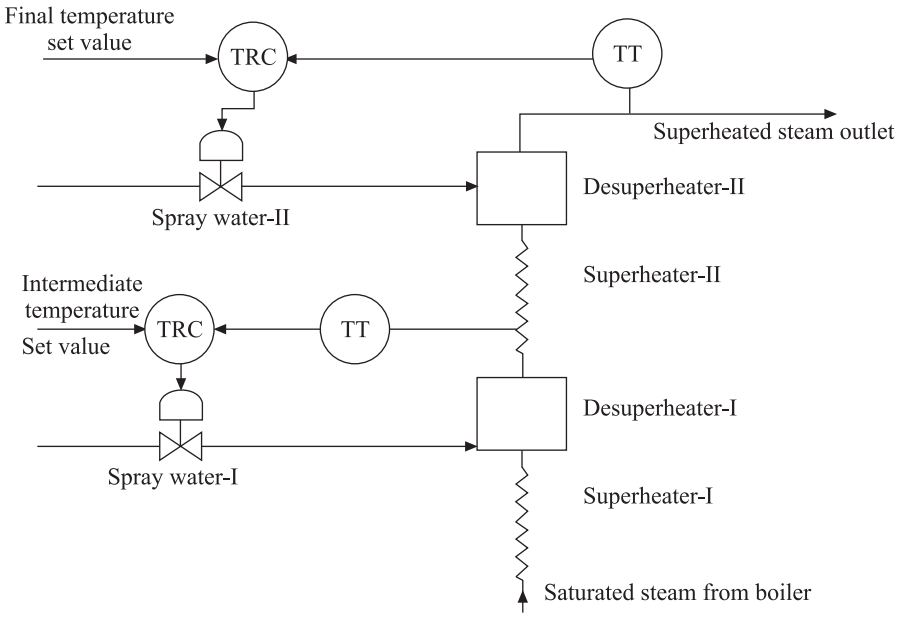


Figure 2.33 Two-stage steam temperature control.

In the large size boilers, the total saturated steam is divided into two streams and controlled with two-stage controllers in each stream and added together in the end. The simplified arrangement is shown in Figure 2.34.

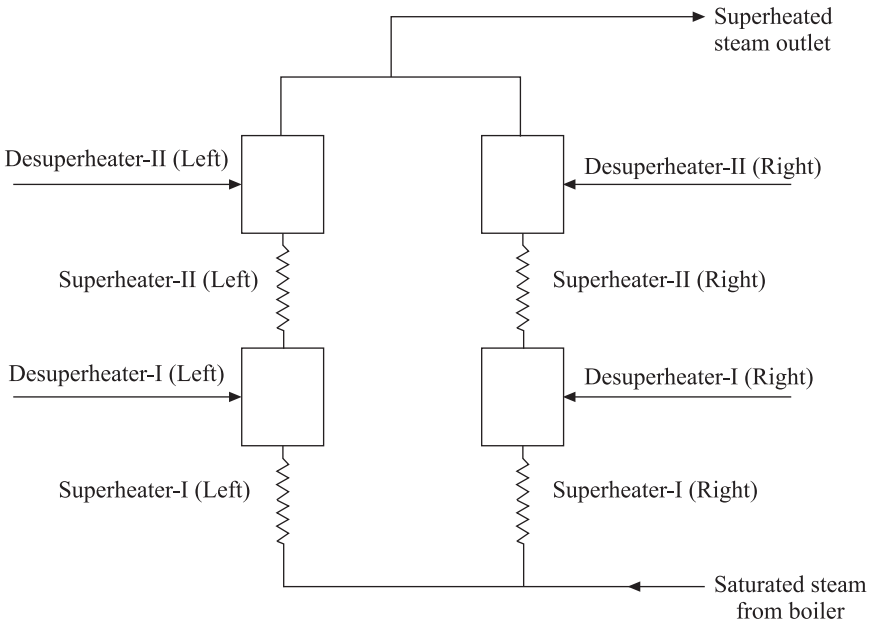


Figure 2.34 Steam temperature control-large boilers.

To use desuperheater spray for steam temperature control, the boiler will be provided with added superheater area. The temperature after the superheater is more than required and the desuperheater will bring down the temperature by spraying to the required level as shown in Figure 2.35.

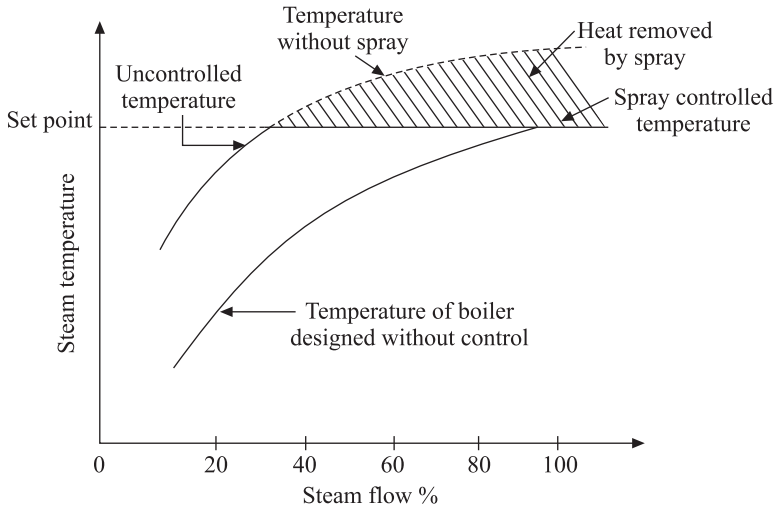


Figure 2.35 Desuperheater characteristics.

Strategies of steam temperature control with desuperheaters

The following two strategies are generally followed where the superheated steam temperature control is practiced with the help of desuperheaters. Though the discussion is centered at spray

type desuperheaters, it is true with shell-and-tube type attemperators. The control strategies are discussed below assuming single stage control, but can be expanded for two stage or two stream-two stage controls.

1. Cascade control with feed forward correction with steam flow.
2. Feed forward-plus-feedback control with total combustion air flow rate as feed forward signal.

1. **Cascade steam temperature control:** The desuperheater control loop can be configured as a cascade loop as illustrated in Figure 2.36. The saturated steam from the steam drum is superheated and if the superheat is excessive, then water is sprayed into the steam as was discussed earlier. The slave temperature controller is placed right after the superheater while the cascade is located at the steam outlet. The feed forward correction is based on steam flow, and the relationship between load and uncontrolled temperature is predicted by the function unit FY. In some designs the steam after desuperheater is returned once more to the furnace to make sure that all water is vapourised.

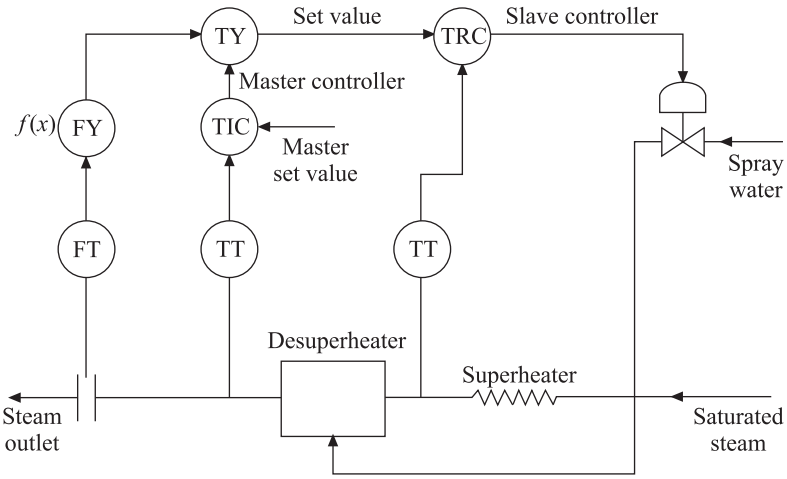


Figure 2.36 Steam temperature control-cascade.

2. **Feed forward-plus-feedback steam temperature control:** Figure 2.37 shows the application of a feed forward plus-feedback strategy. Since air flow rate is an index of firing rate and excess combustion air, the air flow measurement is used as the anticipatory (feed forward) signal. This signal is combined with the output of the steam temperature feedback controller. The output of this summer provides a signal for the spray water flow control valve. Note that the feedback controller is provided with an override controller that provides a minimum output valve tracking signal for the feedback control. This is included so that when the boiler load is below that of the steam temperature control range, the output of the feedback controller will be the signal necessary so that the output of the summer will provide a 'just closed' position of control valve. This function is necessary for good control since on increasing or decreasing steam flow rates, the steam temperature may be at the design temperature level with different firing and air flow rates. This relationship is also affected by the rate of load change. The bias logic is provided to obtain a positive value signal of the output of summer when the signal to the

control valve is reduced to zero percent. As shown this is a 5 percent bias. This allows a set point of the override controller to be a value of 5 percent with control action above and below this signal level. The $f(x)$ logic allows for a non-linear relationship between the measured air flow signal and the position demand signal to the spray water control valve.

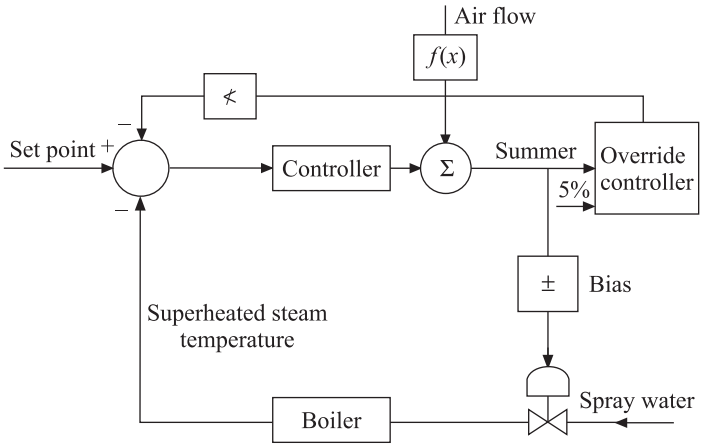


Figure 2.37 Feed forward-plus-feedback control of steam temperature.

Fire side steam temperature control

1. **Excess air control:** One of the methods of fire side temperature control is the raising and lowering of the percentage of excess air in order to control steam temperature. This method tends to improve the overall heat rate of power generation equipment though the thermal efficiency of the boiler itself may be lowered. This method may be used on a boiler that was not specifically designed for temperature control. Although increasing excess air flow increases boiler stack heat losses, turbine thermal efficiency will be increased thus providing greater economic benefit. The control arrangement is as shown in Figure 2.38.

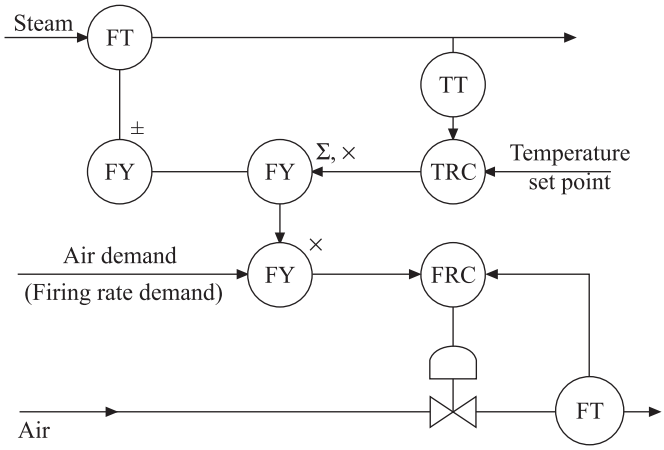


Figure 2.38 Steam temperature control by excess air.

2. **Flue gas bypass control:** The flow stream of the flue gas passing through the superheater can be split so that the mass of flue gas in contact with superheater can be varied. Such a mechanism is called a *superheater bypass damper* and is shown in Figure 2.39.

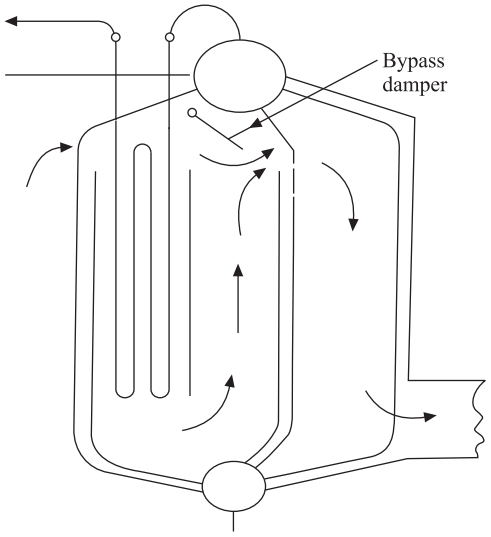


Figure 2.39 Superheater bypass damper control.

The required position of bypass damper as a function of load variation is well established for any boiler design. Therefore, it is a common practice to program their position as a function of load. Readjustments to correct for inaccuracies in the program and changes in the characteristics of the boiler is accomplished by feedback control of temperature using proportional and integral action. Being applied through a multiplier, the feedback loop gain varies directly with load and this tends to cancel the inversely varying process gain. The control schematic is shown in Figure 2.40

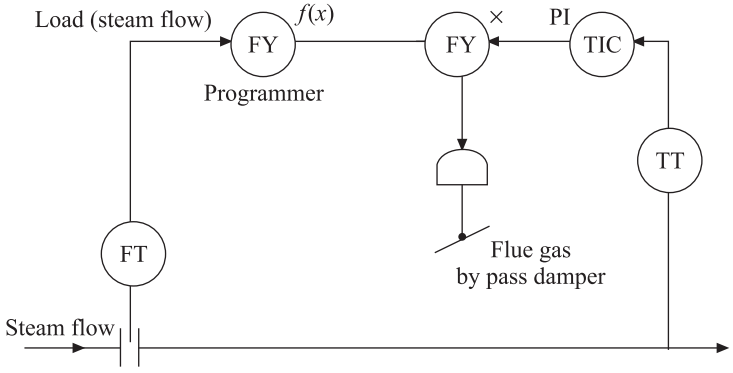
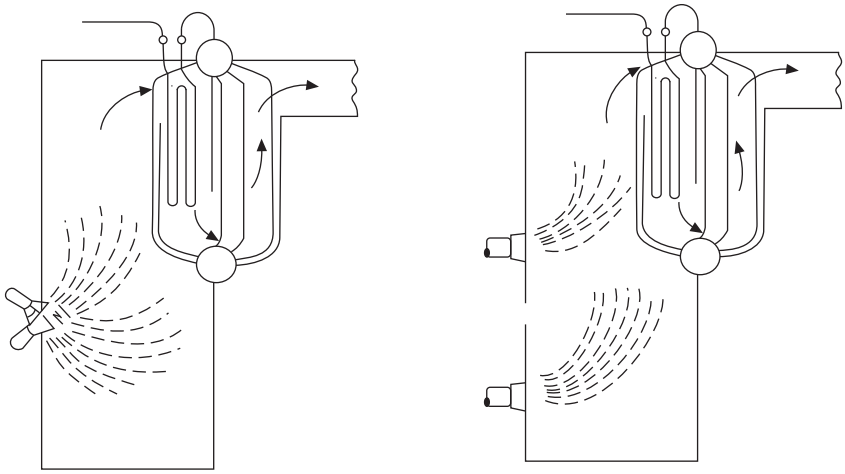


Figure 2.40 Steam temperature control-flue gas by pass.

3. **Adjustable burner or burner tilting control:** In this method of steam temperature control, the burners mounted in the furnace corners are arranged so that the flame can be tilted up or down from horizontal. By this arrangement the temperature of the flue gas entering the superheater can be changed. The burner flame is aimed at a tangent to an imaginary circle in the centre of the furnace, and the burners in the four corners of the furnace are tilted at the same angle. The result is a 'fire ball' in the centre of the furnace, which rotates and which can be raised or lowered in the furnace by changing the tilt of the burners. Lowering the fire ball increases furnace heat absorption, which lowers the flue gas temperature as it enters the superheater. Raising the fire ball decreases the furnace heat absorption with the opposite effect on the temperature of the flue gases entering the superheater. Figure 2.41(a) demonstrates the above whereas Figure 2.41(b) shows a furnace with burners mounted in fixed furnace wall positions. Note that the burners are mounted at higher and lower elevations. By varying the ratio of the fuel fired in the upper row of burners to that of in the lower row of burners, the furnace heat absorption can be modified, thereby changing the temperature of the flue gases entering the superheater. The control schematic will be same as that shown in Figure 2.40 for flue gas bypass but for the mechanical linkage arrangements. The mechanical linkages should be designed so that the burner angle can be tilted (or the ratio of the fuel between lower and upper row of burners can be changed).



(a) Tilting burners (b) Adjustable and additional burners

Figure 2.41 Adjustable burner/burner tilting control.

Steam temperature control-combination of both water side and fire side controls

Temperature control by desuperheater can be used to supplement the gas manipulation or burner's position tilting. This effectively changes the furnace heat transfer area, resulting in temperature changes of flue gases leaving the boiler. Spray is frequently used with these systems as an override control. One such combination of fire side and water side control is illustrated in Figure 2.42.

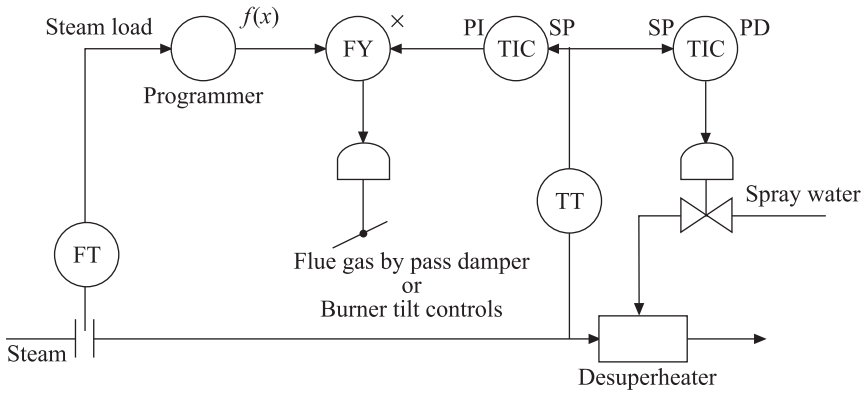


Figure 2.42 Steam temperature control-combination.

2.4.3 Steam Pressure Control

The balance between the heat inflow and heat outflow of a boiler is indicated by drum pressure. A balance between the demand for steam (depends on the plant load) and the supply of steam from all boilers in a power station can be established by controlling the common bus pressure. A change in steam pressure can be expected after a delay of a few seconds to a minute from a change in firing rate. It again depends on the boiler condition and the load level. Hence, a feed-forward control can improve pressure control by adjusting fuel as soon as a load change is detected, instead of waiting for pressure to change first. In a steam thermal power station where a number of boilers and turbo alternators are in operation, a common steam bus or steam header is used to receive steam from all boilers in operation and distribute to all turbo alternators in operation. At a balanced condition, when temperature and pressure are under control, the total generation of steam and consumption are same. To meet the load fluctuations, the steam drawn from the header varies and hence the pressure. Therefore a need for automatic pressure control arises. As the pressure can be varied only by adjusting the firing rate in the boilers, the controller output can be shared among the number of boilers. The proportion of sharing among boilers will be based on the condition of the boilers. A common steam supply system with 'N' number of boilers and equal number of turbo alternators is shown in Figure 2.43. The steam header pressure is used as master pressure signal to decide the firing rate demands of various boilers.

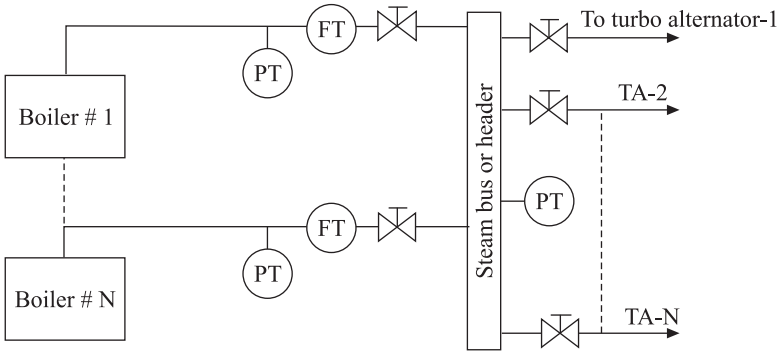


Figure 2.43 Common steam supply system.

Feedback steam pressure control

If one to one combination (one boiler to one turbo alternator) is followed, the parameter used for setting fuel demand or firing rate or combustion control may be either of steam pressure or steam flow. With several boilers supplying a common header in parallel, it is generally desirable to provide a way to adjust the load distribution among the boilers. It is successfully done with feedback control of header pressure. Depending on the load and the performance of the individual boilers, the most efficient operation may be achieved with some boilers are shut down, some boilers are base-loaded (constant firing rate), and the remaining boilers allowed to swing with the load (variable firing rate).

Figure 2.44 shows a feedback plant master control to generate total fuel demand (firing rate demand) taking steam header pressure as input and controlled variable. Total fuel demand is distributed among boilers as discussed above. Each boiler master provides a bias adjustment and an auto/manual transfer switch. In manual, the operator can reduce the firing rate to a low fire condition for shutdown, or hold firing rate at appropriate base loading condition. In auto, the boiler master follows the master firing rate demand signal except as altered by the bias adjustment. The operator can adjust the boiler master bias up or down to increase or decrease its share of the load.

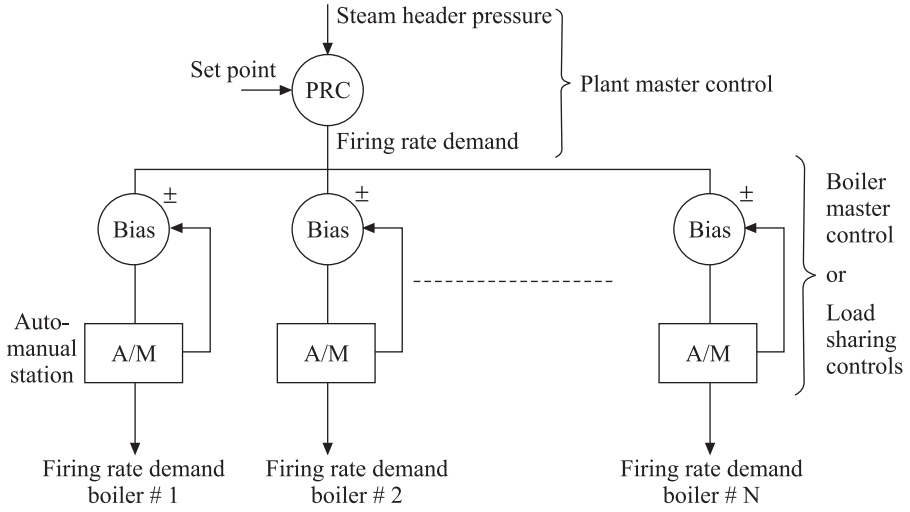


Figure 2.44 Boiler master control.

The firing rate demands generated by the plant master controller through boiler master controllers (load sharing controllers) for different boilers become set points for combustion controllers of the boilers concerned. The combustion control system will be discussed in detail under 'Controls in Air-fuel Circuit' in Chapter 3.

Feed forward-plus-feedback steam pressure control

To get faster response from the master controller for the firing rate demand for individual boilers, the total steam flow from the plant is used as feed forward signal. As it is not practical to measure steam flow in or out from the steam header by an individual flow meter, either the steam generation

from individual boilers or the steam consumption of individual turbo alternators are added together. One such arrangement of feed forward-plus-feedback master control is shown in Figure 2.45. In this arrangement the total steam flow of all boilers is the feed forward demand. The proportional multiplier function is adjusted at the input of summer so that a change in steam flow will produce the correct steady-state change in firing rate demand. The steam pressure controller provides the correct adjustment of the firing rate demand for the necessary overfiring or underfiring to adjust energy input.

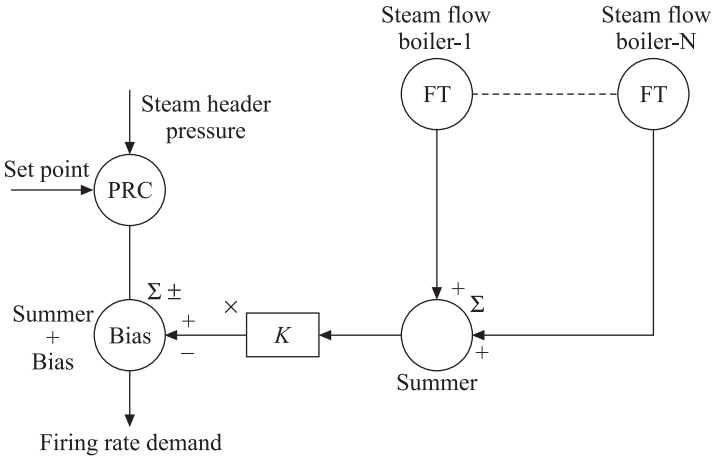


Figure 2.45 Feed forward-plus-feedback master control.

In the normal power plant installation, the change in steam header pressure is almost entirely due to the change in steam flow rate on the user demand side of the header. If the pressure-drop between boiler and steam header is high, then the change in steam flow rate may cause a larger change in steam header pressure due to changes in supply side pressure-drop. These two pressure changes mean different things to the system. A pressure change on the demand side means that the firing rate should be changed because the user wants more steam. A change in pressure drop on the supply side is an indication of a needed change in firing rate to change the stored energy that is represented by boiler pressure.

2.5 IMPURITIES IN WATER AND STEAM

As we have already seen, the boiler feed water consists of two parts, namely condensate water and make up water. Condensate water from turbine is already treated for impurities and the makeup water component is also treated from raw water. In this section we will discuss in short, about the various impurities which may be present in the raw water and the treatment required to remove all those impurities before letting the feed water into boiler. The superheated steam coming out of the boiler is supposed to be free of all impurities the water might have contained.

2.5.1 Impurities in Raw Water

Raw water from natural sources usually contains dissolved gases, dissolved salts and minerals. Some organic and inorganic materials are also found in suspension. Dissolved gases are mainly

oxygen and carbon dioxide and generally air, hydrogen sulphide and other gases. Dissolved salts are carbonates, sulphates and chlorides of calcium, sodium and magnesium. Iron, aluminum or silica salts are present occasionally. Alumina and silica in the form of mud and silt, sewage and industrial waste are there as suspended matters. All the impurities are to be removed by water treatment. Even after that some impurities may find their way into the boiler. They are to be neutralized by internal chemical reaction and removed by blow down operation.

2.5.2 Effects of Impurities

The following are the bad effects experienced by the boiler and other equipment due to feed water entering the boiler with impurities:

1. Scaling
2. Corrosion
3. Foaming
4. Priming, and
5. Embrittlement

Scaling

The solubility of some salts decreases with increasing temperature. Then the chemical saturation of such salts in water is reached. The precipitation and sedimentation occur, forming a layer of scale on the heating surfaces and loose precipitates in drum. Also supersaturated layer of water lying on the heating surface forms scales by crystallization. Salts of calcium and magnesium are the main cause for scaling and to a lesser extent silicates also. Boiler tubes, boiler drum, heater tubes, feed water piping etc. get affected by scaling. Scaling on the piping system chokes the flow and on the heat transfer surfaces decreases the transfer. Overheating, blistering and rupturing of tubes are expected when the accumulation of scale becomes thick. The impurities can be made to precipitate as a soft sludge by boiler water conditioning with chemicals added. The soft sludge thus formed can be removed by blowing down operation. Though steps are taken to prevent scaling, cent percent prevention is not possible. The scale formed during long operation of boiler has to be cleaned during boiler overhauling. Electric-powered rotary brushes and cutters are pushed through the tubes for cleaning scale. Weak acid is also used for cleaning scale sometimes.

Corrosion

Corrosion is caused due to acid condition of water. Dissolved gases like oxygen and carbon dioxide aid corrosion. Chlorides present in boiler water help the corrosion process. Destructive conversion of metal into oxides or salts is called *corrosion*. Corrosion can occur at any place in water loop. Boiler tubes, piping, pumps and heat exchangers are normally affected by corrosion. Dissolved oxygen in feed water should be kept at a level below the safe value. Normally 0.5 cc per litre is considered safe and for high pressure units, it should be even less. The boiler water is always maintained alkaline to prevent corrosion.

Foaming

Too high a concentration of dissolved salts, saponification of the boiler water through mixture of oil or grease with alkali and floating organic matter are the sources of producing foam in the boiler drum. Foaming due to concentration of salts can be avoided by proper water treatment.

Blowing down of concentrated water also helps avoiding foaming. Foaming severely affects the quality of steam as it causes excessive carry-over of water with steam.

Priming

If there is too much of moisture carry over along with steam, then the boiler drum is said to be priming. The presence of impurity-bearing droplets of water in the steam is called *carry-over*. When the water is vaporised in the superheater, the solid impurities are left behind to get deposited on superheaters. The impurities which can float are carried over along with steam to even turbine stage where they may get deposited over turbine blades.

Embrittlement

Embrittlement is considered to be one of the serious effects. The failure due to embrittlement may cause even explosion, though the occurrence is rare. Presence of sodium hydroxide is the main cause for embrittlement which can be detected only on minute scrutiny. Embrittlement is due to loss of toughness in the metal and creation of minor cracks on the surface of the tubes.

2.5.3 Measurement of Impurities

To find out approximately the amount of impurities present in water and steam, the following analysis/measurements are done.

1. Conductivity
2. pH (Hydrogen ion concentration)
3. Dissolved oxygen analysis.

Conductivity

Conductivity measurements are done for ascertaining the salt contents in feed water, condensate and steam. Conductivity of pure water is very low. The presence of impurities increases the conductivity. Measurement of conductivity can be used to determine the amount of total dissolved solids in water. The acceptable limit is approximately 0.3 μmhos/cm^3.

Electrolytic conductivity is the ability of a solution to pass an electric current. Conductivity which is reciprocal of resistivity would increase with increasing impurities present in the solution. Conductivity of a solution is measured in micromhos per centimeter or micro-siemens per centimeter at 25ºC, and this represents the reciprocal of resistivity of a centimeter cube of water between two plates 1 cm^2 in area and placed 1 cm apart.

Conductivity is measured by a conductivity cell, the dimensions of which and distance apart of electrodes are chosen to give a convenient range of measurement. The relationship between resistance, conductivity and characteristic constant of the cell is as follows

$$\text{Resistance} = \frac{\text{Resistivity} \times \text{Length of the sample}}{\text{Cross-sectional area of plates}} = \frac{\rho \ell}{a}$$

and

$$\text{Conductivity} = \frac{1}{\text{Resistivity}} = \frac{1}{\rho} = \frac{\ell}{Ra} \text{ mho/cm} = \text{K}$$

where

R = Cell resistance in ohms.

ρ = Resistivity in ohms cm^2/cm

ℓ = Length of the sample in cm

a = Area in cm^2

K= Conductivity in mhos – cm/cm^2

$\frac{\ell}{a}$ = Cell constant in 1/cm = C

For a given set of electrode dimensions, the term $C = \frac{\ell}{a}$ is a constant (cell constant), which makes R a measure of conductivity χ.

In contrast to measurements of pH value which depends on the hydrogen ion concentration alone, the conductivity is a function of the concentration figures of all ions present in the sample. Typical ranges of conductivity meters are listed below.

S.No.	Level	Cell constant C	Ranges $\mu_{mhos/cm.}$	
1.	Very low concentration	0.006	0–0.6	; 0–2;
			0–4	; 0–10
2.	Low concentration	0.06	0–10	; 0–50
			0–200	; 100–600
3.	Medium concentration	1.00	200–1000	; 400–2000
			1000–5000	; 2000–12000

The conductivity is a measure of the salt content. Strictly speaking, the measurement is only correct for one particular kind of salt. Since, however, the general composition of the feed water is reasonably constant in the average case, a sufficiently correct result is obtained. As conductivity metre is principally used for supervising the salt content, it is calibrated in mg Nacl per litre instead of micro mhos per centimeter.

(1 mg NaCl/litre $\simeq$ 1.9 μmhos/cm at 20°C)

The accuracy of conductivity measurements depends to a considerable extent on shape and arrangement of electrodes. Special assemblies are available for low and medium concentrations.

Figure 2.46 shows a detecting element for very low and low concentrations. The electrodes are arranged concentrically. The external electrode (enveloping electrode) is connected to the assembly fitting and thus grounded via the piping or tank, so that wall effects cannot influence the measurements. The internal electrode is insulated and encloses a resistance thermometer for temperature correction. The assembly for very low concentrations has a somewhat thicker internal electrode compared to that for low concentration assembly.

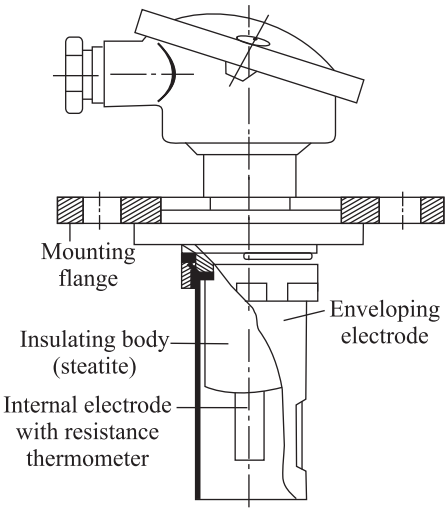


Figure 2.46 Conductivity meters for low concentrations.

To prevent polarization effects, one applies an ac voltage in the measurement circuit as shown in Figure 2.47. The assemblies are usually mounted in a flow chamber, but immersion mounting is feasible as well. For pressures exceeding 10 kg/cm^2 a pressure reducer must be provided.

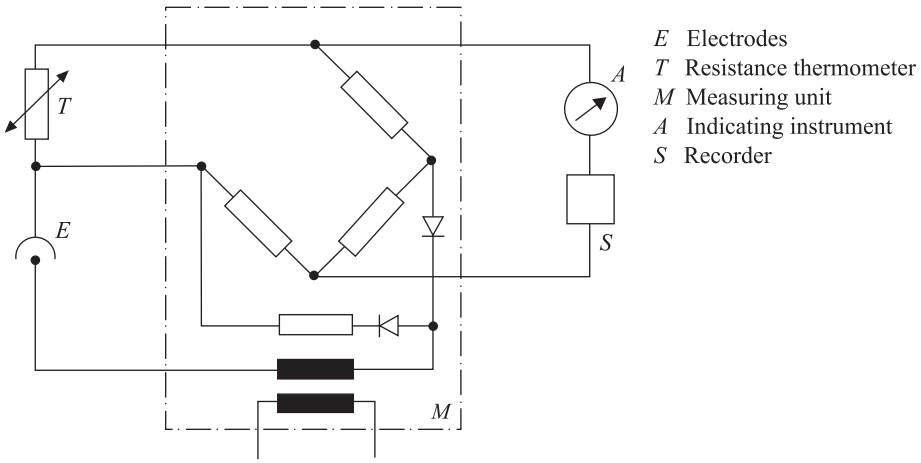


Figure 2.47 Circuit of the conductivity meter for low concentrations.

For assemblies of medium concentrations, a plastic sleeve houses four annular platinum plated electrodes as shown in Figure 2.48. The two shielding electrodes are electrically connected; they circumscribe the electric field. The resistance thermometer which provides temperature correction is inside a protecting tube alongside the electrode sleeve. The corresponding electric circuit is shown in Figure 2.49. This type of assembly, suitable for pressures up to 1 kg/cm^2 is usually mounted in a flow chamber.

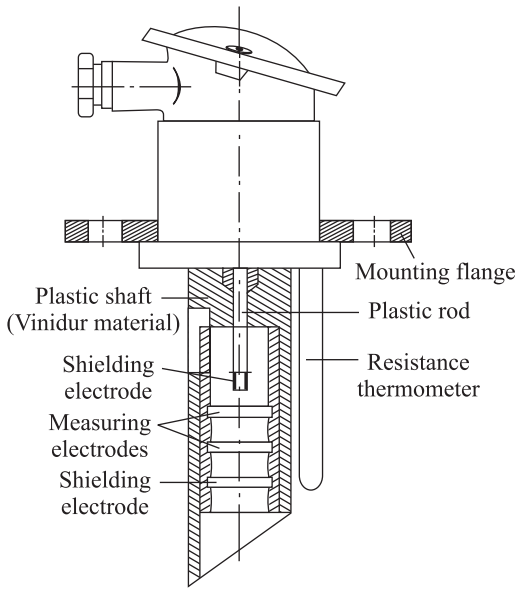


Figure 2.48 Conductivity meters for medium concentrations.

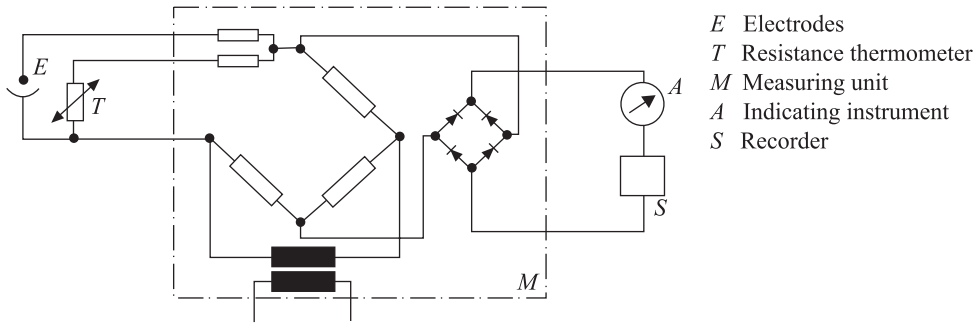


Figure 2.49 Circuit of the conductivity meter for medium concentrations.

Precautions to be taken: The conductivity is influenced not only by the quantity of salts, but also by the content of dissolved gases like NH_3 and CO_2 and hence are to be eliminated from the sample. The elimination of NH_3 is done generally by passing the sample through a filter filled with strong acidic cation-exchange resin. The CO_2 is then eliminated by passing nitrogen through the sample.

Hydrogen ion concentration (pH):

Pure water is tasteless, odourless, and neutral. Natural and commercial waters are never pure. Because water is a most universal solvent, and because of ionization, either OH^- or H^+ ions will predominate, causing either an alkaline or acidic condition. A scale, called pH, has been devised to measure the intensity of acidity or alkality of a solution. An exact definition of the pH number is that it is the logarithm of the reciprocal of the hydrogen ion concentration (grams per liter).

$$\text{pH} = \log_{10}\left(\frac{1}{\text{H}^+}\right) = -\log_{10}(\text{H}^+)$$

The pH value is a measure of the strength of an acid, of the neutral character of a solution, and also of the strength of a base. The law of mass action, which applies to all chemical reactions states for the dissociation of water, $H^+ \times OH^- = 10^{-14} = K$ (at 25°C). Just as temperature is measured in degrees, so is acidity or alkality measured in pH values from 0 to 14. pH-1 is strongly acid, pH-14 is strongly basic, and pH-7 a neutral solution. pH-5 is 10 times as acidic as PH-6; pH-4 is 10 times as acidic as pH-5 and 100 times as acidic as pH-6. For instance, if H^+ is 10^{-9}, then OH^- is 10^{-5} grams ions per litre $(\because \text{H}^+ \times \text{OH}^- = 10^{-14} = \text{K})$ and pH – 9 designates the solution which, of course, is alkaline as OH^- ions predominant. Refer to Figure 2.50 for pH scale.

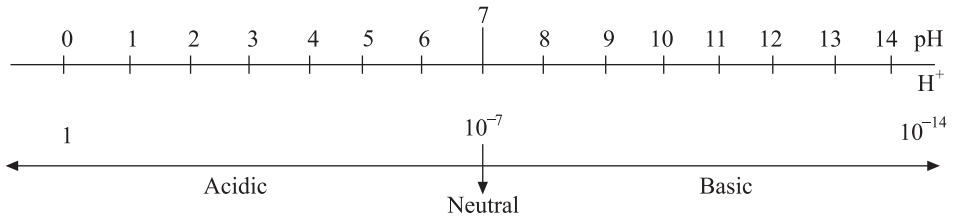


Figure 2.50 pH scale.

Dissolved oxygen analysis

As we have already seen, the dissolved oxygen in feed water is a corrosion accelerator. The unit used to mention dissolved oxygen is ppm. Analysis to quantify dissolved oxygen can be done either by laboratory method or by on-line analysis. Chemical titration method is normally used to find out the quantity of dissolved oxygen from the sample collected and immediately presented for the test. The validity of measurement will be under suspicion as the delay causes absorption of oxygen from the atmosphere into the sample. Special portable kits are used to carry out the testing on the spot. It is always better to use analysers which can test on line. Two such analysers are discussed briefly here.

(a) Wallace and Tierman dissolved oxygen analyser
(b) Kathrometer.

(a) Wallace and Tierman dissolved oxygen analyser: Concentration of dissolved oxygen in boiler water is measured by electrochemical analysis in this analyser. It is continuous and automatic. The analyser can be divided into two units called *sampling cell unit* and transmitter-indicator unit. Reference electrode, platinum measuring electrode and calibration cell are accommodated in the sampling unit. Sample flow, pressure, temperature and conductivity are measured and controlled here.

The transmitter-indicator unit consists of electronic circuits required for measurement, transmission and calibration. The indicating meter or recorder is normally calibrated in ppb (parts per billion). Ranges may be from 0 to 25 and 0 to 50 ppb with multification factors of 1 and 10. That means, in addition to 0 to 25 and 0 to 50 ppb ranges another set of ranges 0 to 250 and 0 to 500 ppb are made available. The nominal output voltage in the range of 0–5 mV can be converted into standard signals of either 4–20 mA or 1 to 5 V DC. A simplified block diagram of Wallace and Tierman dissolved oxygen analyser is shown in Figure 2.51.

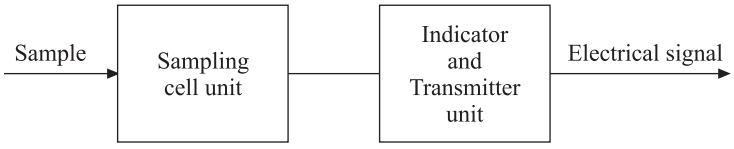


Figure 2.51 Wallace and Tierman dissolved oxygen analyser.

(b) Kathrometer: When the water sample is cooled and scrubbed by hydrogen, the dissolved oxygen present in the water gets displaced to form a mixture of hydrogen and oxygen. Wheatstone bridge circuit is used to measure the amount of dissolved oxygen. The heated wires of the bridge circuit is exposed to hydrogen in two opposite arms and to hydrogen-oxygen mixture in the other two arms. The unequal cooling of the heated filaments makes the bridge imbalanced. The unbalanced voltage can be calibrated to indicate the dissolved oxygen. The Kathrometer consists of four major parts to perform the above functions. They are cooler, scrubber, hydrogen producer and Wheatstone bridge circuit. Figure 2.52 shows the simplified Kathrometer.

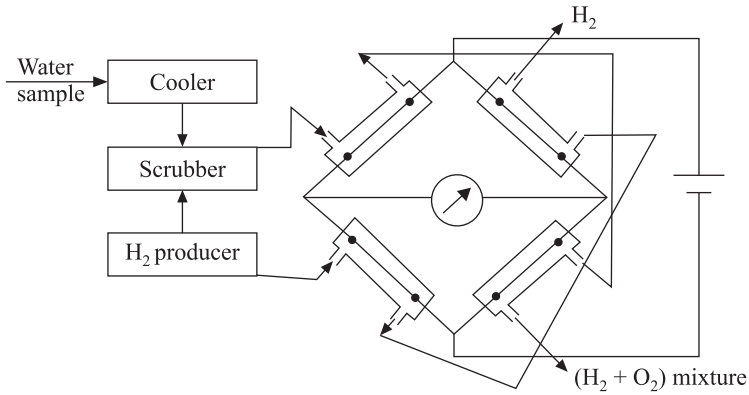


Figure 2.52 Kathrometer.

2.5.4 Feed Water Treatment

The fact that impurities present in feed water can have many bad effects on boiler and turbine clearly suggests the importance of feed water treatment. After knowing the condition of the water with the help of measurements for conductivity, pH and dissolved oxygen, the necessary treatment plans can be made. The total treatment required can be broadly classified into two categories, namely,

1. External treatment – to be done before supplying water to the boiler.
2. Internal treatment – to be carried out after the water is let into the boiler.

External treatment

Mechanical, thermal and chemical treatments are possible. Sedimentation, filtration and interior painting fall under mechanical treatment. Deaeration and evaporation processes are thermal ones. Precipitation using prepared reagents and exposing to a zeolite to obtain ion exchange are grouped under chemical treatment processes. Ion exchange process is done before the water enters the boiler, whereas precipitation is possible both internally and externally.

Filtration: Coagulation is carried out with the addition of special chemicals like aluminum sulphate [$Al_2(SO_4)_3$] with suspended solids and turbidity. The coagulated matter settles down in the clarifier which can be removed. Positive filtration is required when the turbidity of the clarified effluent is high. Gravity filters and pressure type filters are used for this purpose. Pressure type filters are normally preferred. A granular material like sand is generally used for filtration. The pressure difference across the granular medium indicates the accumulation of solid. The bed has to be backwashed once the limit reaches. Organic compounds can be removed with the help of activated carbon and residual chlorine by chlorination process.

Deaeration: Removal of dissolved gases like oxygen and carbon dioxide by heating and agitating is done by deaeration or degasification process. With increase in temperature, the solubility of these gases becomes less and almost to zero at the boiling temperature. The heating can be done by the extracted steam from turbine. After heating up, the water is sprayed from top so that the gases can escape through vent and the water gets collected in a storage tank. The deaerator with storage tank is shown in Figure 2.53.

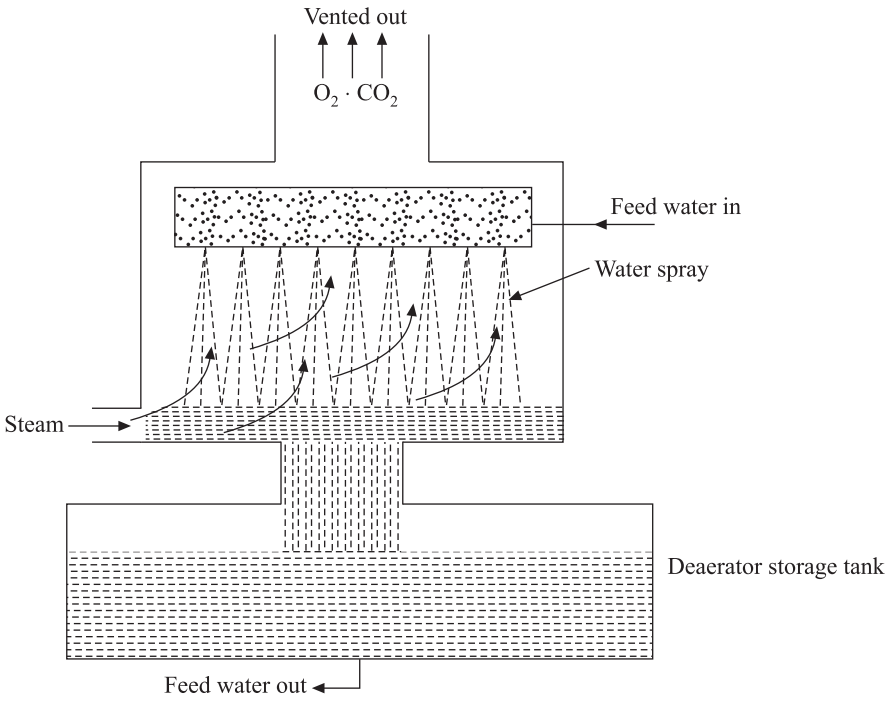


Figure 2.53 Deaerator with storage tank.

Evaporation: The evaporation process is carried out after filtration, coagulation and softening. The remaining dissolved and suspended solids are removed effectively by vaporizing water with heat.

Precipitation: Precipitation process is used to remove dissolved salts from feed-water. Lime [Calcium hydroxide – $Ca(OH)_2$] and soda ash [sodium carbonate – Na_2CO_3] are used to remove calcium and magnesium salts in hot lime-soda process of precipitation. The resultant products, namely, calcium carbonate and magnesium hydroxide which are insoluble in water get precipitated and settle down in the bottom of the vessel.

Ion exchange process: In water solution, some materials will exchange their base radical with anions. For softening water, exchange of calcium for sodium is accomplished. Sodium zeolite [Na_2 ($Al_2Si_2O_8$) or Na_2Z] is used for this purpose. Organic zeolite containing no silica is also used for ion exchange purpose. Sodium zeolite (Na_2Z) and organic zeolite (H_2Z) have the ability to exchange one ion for other, hold it temporarily and give it up to a string regenerative solution.

Demineralisation: Demineralisation is the process by which the dissolved salts present in feed water are removed by ion exchange. Anion resin (Na_2Z) and cation resin (H_2Z) are used for ion exchange purpose. Hydrogen ion is exchanged for the cations calcium, sodium and magnesium when H_2Z is used. Anion resin absorbs the anion chloride, nitrates and sulphates. Ion exchange process is reversible and hence the resins can be restored by regeneration. A typical demineralization plant is shown in Figure 2.54.

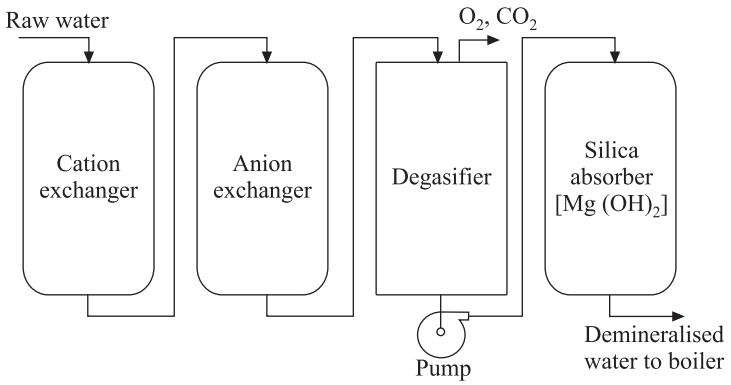


Figure 2.54 A typical demineralisation plant.

Due to condenser leakage and presence of metallic ions of iron and copper pipelines, the treated water may pick up impurities. Hence the condensate water which is already treated has to undergo a process called *condensate polishing* to remove the picked up impurities. Mixed bed units with both cation and anion resins called *demineralising vessels*, are used for this purpose. These units filter out impurities like suspended solids in addition to removing dissolved salts.

Internal treatment

Treating the water which is already in the boiler is called *internal treatment*. There is always a steady accumulation of dissolved solids which escaped even after external treatment. Though it is slow, the concentration of dissolved solids will increase in the boiler water. Unless the concentrated water is deconcentrated or blown down regularly, foaming and carryover take place encouraging scaling, corrosion and embrittlement. The blow down operation may be done intermittently or continuously. The amount of blow down depends on allowable solids concentration. It is always expressed as below:

$$\% \text{ Blow down} = \frac{\text{Quantity of water blown down}}{\text{Quantity of feed water admitted}} \times 100\%$$

Chemical reagents are added periodically to the water already in the boiler. Some of the chemicals employed and the purpose for which they are employed are given in Table 2.1

Table 2.1 Chemicals used for internal treatment.

S.No.	Chemical	Purpose
1	Sodium hydroxide	To establish alkaline pH, and precipitate magnesium
2	Sodium carbonate	To precipitate calcium
3	Sodium aluminate	To coagulate finely divided precipitates into a floc and also to precipitate calcium and magnesium
4	Sodium phosphates (trisodium, disodium or monosodium)	To precipitate calcium in form favourable to riddance through blow down
5	Sodium sulphite	To complete deoxidation
6	Colloids	Protective colloids such as tannin; and reactive organic forms to make a fluid sludge of suspended particles.
7	Acid	To control alkalinity

An electrolytic apparatus having 'sacrificial anode' is installed in the boiler drum. The special metallic anode is consumed during the period while protecting the boiler against scaling and oxygen corrosion.

Steam purity: The quality of steam delivered by the boiler purely depends upon the purity of the steam. The quality steam means that it is at required temperature and pressure in addition to having least carryover and least boiler salt concentration. Impure steam causes scaling, corrosion and embrittlement. Scrubbers and steam-washers are used in the drum to get required steam purity. Steam purity can be determined by measuring conductivity of the condensed sample using conductivity meters. The electrical conductivity can be taken as the representative measure of impurity in the water.

Table 2.2 gives the summary of feed water treatment discussed so far.

Table 2.2 Summary of feed water treatment

S.No.	Impurity	Effect	Kind of treatment
1	O_2	Corrosion	Chemical deoxidation Thermal deaeration
2	CO_2	Corrosion	Thermal deaeration
3	Ca, Mg, salts	Scale	External softening Internal softening
4	Fe	Scale	Ion exchange
5	SiO_2	Carry over scale	Deionisation
6	Na alkalinity	Embrittlement, foam	Acid neutraliser
7	Total dissolved solids (TDS)	Priming, foam	Deconcentration
8	Turbidity	Sludge sediment	Coagulation, sedimentation, filtration
9	Oil	Foam	Coagulation, filtration, surface blow-off

WORKED-OUT PROBLEMS

PROBLEM 2.1 Feed water flow to the boiler is measured with orifice plate sensor designed to give the maximum differential pressure of 10 m for 100 T/hr water flow. The differential pressure transmitter is used for converting the differential pressure to a 4–20 mA dc linear signal. A square root extractor circuit is introduced to convert the current signal into a voltage signal (1–5V DC) linear to flow rate. (a) Design measurement system for the above (b) Also give the calibration chart for calibrating the transmitter along with square root extractor.

Solution: **Given:** For orifice, $Q \propto \sqrt{h}$ or $h \propto Q^2$.

Q_{max} = Maximum flow rate = 100 T/hr.

h_{max} = Maximum differential pressure = 10 m.

Transmitter: (Output current – 4mA) $\propto h$

$\because 20 - 4 = 16$ mA $\equiv h_{max}$

Square root extractor:

Input: 4–20 mA

Required output: 1 – 5 V proportional to 0 – 100 T/hr flow rate.

A schematic measurement system is shown in Figure 2.55

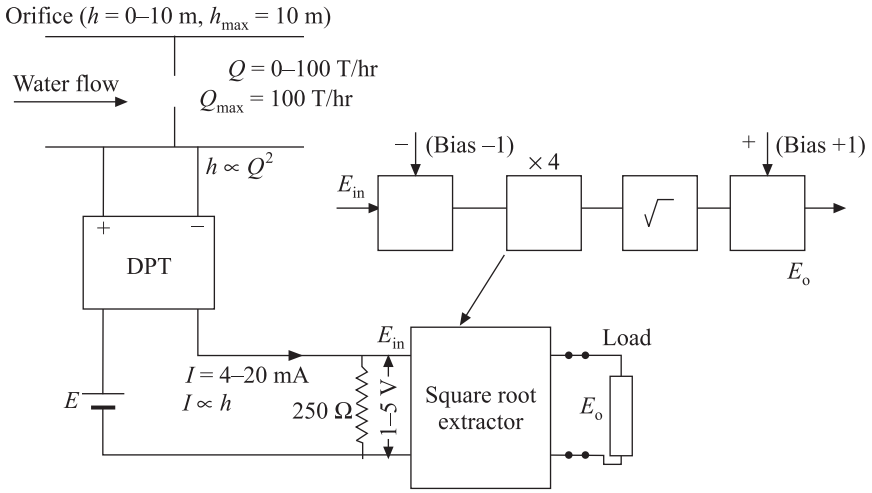


Figure 2.55 Measurement system for Problem 2.1.

Requirement: E_o = 1 to5 V proportional to Q (0 – 100 T/hr)
Let us take five critical flow rates which can be extended to whole range and tabulate the values as below:

Q T/hr	h m	I mA	E_{in} V	E_o V
0	0	4	1	1
25	0.625	5.00	1.25	2
50	2.500	8.00	2.00	3
75	5.625	13.00	3.25	4
100	10	20	5	5

Up to E_{in} it is calculated and E_o is fixed as required. It can be proved that the following function will satisfy the above need for square root extractor block.

$$E_o = \sqrt{4(E_{in} - 1)} + 1$$

This can be achieved by putting a conditioning resistor (highly stable) of value 250 Ω to convert 4 to 20 mA into 1–5 V signal, negative bias of constant value 1, multiplier of 4, square root extractor and a positive bias of constant value 1 as shown in Figure 2.55. Working of the system can be verified for other flow rates as shown below:

Q T/hr	h m	I mA	E_{in} V	E_o V	$Q \propto E_o$ T/hr
0	0	4	1	1	0
20	0.40	4.64	1.16	1.8	20
40	1.60	6.56	1.64	2.6	40
60	3.60	9.76	2.44	3.40	60
80	6.40	14.24	3.56	4.20	80

Sample calculation for Q = 60 T/hr.

$Q^2 \propto h$. In this problem Q varies form 0–100 T/hr

h varies from 0–10 m

$\therefore$ for Q = 60 T/hr, $$h = h_{max}\left[\frac{Q}{Q_{max}}\right]^2 = 10 \times \left[\frac{60}{100}\right]^2$$

$$= 3.6 \text{ m.}$$

$$I = \left[\frac{20-4}{10} \times 3.6\right] + 4 = 5.76 + 4 = 9.76 \text{ mA}$$

$$E_{in} = I \times 250\ \Omega = 2.44 \text{ V}$$

$$E_o = \sqrt{4(E_{in} - 1)} + 1 = \sqrt{4(1.44)} + 1 = 3.4 \text{ V}$$

$\therefore$ Q to be read as $= \frac{100}{4} \times (3.4 - 1) = 60$ T/hr

Calibration chart: For calibrating the transmitter with square root extractor unit with respect to flow, we have to apply equivalent differential pressure and measure the corresponding output voltage. The following chart has to be followed for 11 points calibration method.

Q T/hr	h to be applied m	E_o to be measured V
0	0	1
10	0.1	1.4
20	0.4	1.8
30	0.9	2.2
40	1.6	2.6
50	2.5	3.0
60	3.6	3.4
70	4.9	3.8
80	6.4	4.2
90	8.1	4.6
100	10	5

PROBLEM 2.2 An iron-constantan (Fe-K) thermocouple is used to measure the superheated steam temperature. The thermocouple head is placed near the furnace wall whose temperature is around 100ºC. What will be the percentage error if the temperature meter is located in the control room and only copper cable runs from thermocouple head to control room. Assume the range as 0–600ºC.

Solution: By principle of thermocouple, the emf generated will be proportional to the temperature difference between the hot junction and cold junction. It is important to maintain the cold junction at 0ºC (or at any other constant temperature which can be corrected later on). In the case referred

to in the problem, compensating leads are not used from thermocouple head to control room and the cold junction at the control room is not maintained at 0ºC for accurate results.

In this case, the cold junction temperature is 100ºC and hence the emf generated will be less correspondingly. Also there is no compensating leads from thermocouple head to control room. Hence the overall error will be 100ºC

$$\text{Percentage error} = \frac{100°\text{C}}{\text{span/range}} \times 100\%$$

$$= \frac{100}{600} \times 100 = 16.67\%$$

PROBLEM 2.3 A two–wire 4–20 mA electronic pressure transmitter is used with a load independency of 600 Ω at 24 V power supply. One indicator and one recorder of 1 to 5 V input are already connected to the transmitter.

(a) If a controller has also to be connected, what should be the maximum input load resistance of the controller allowed?

(b) If a controller with 400 Ω has to be connected addionally, what should be the minimum power supply voltage? (Assume 50 Ω/volt loading increase)

Solution: The situation is schematically represented in Figure 2.56.

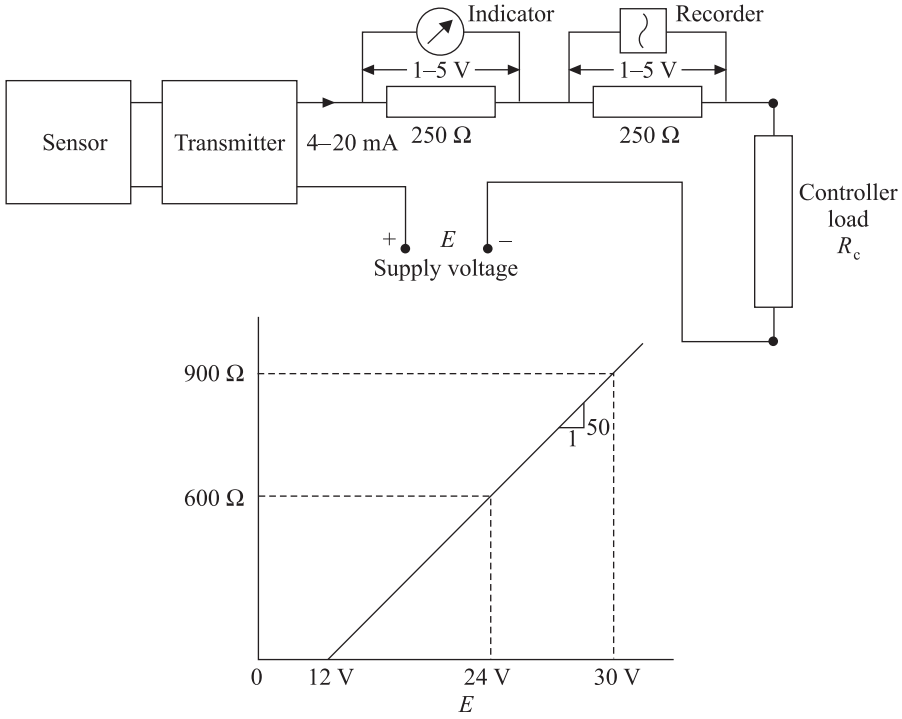


Figure 2.56 Working diagram for Problem 2.3.

(a) Load resistance for the indicator: 250 Ω

[To convert 4–20 mA standard output signal from transmitter into 1–5 V signal, a conditioning resistor of 250 Ω has to be put in series as shown)

Similarly, load resistance for the recorder: 250 Ω

∴ Total load already connected = 250 + 250 = 500 Ω

Allowable load with load independency: 600 Ω

∴ The maximum load allowed for the controller = 600 – 500 = 100 Ω

Hence, a controller with less than 100 Ω input resistance can be connected to the transmitter in addition to indicator and recorder without losing load independency.

(b) Controller input resistance: 400 Ω

Total load now will be: 250 + 250 + 400 = 900 Ω

Allowable load with 24 V power supply = 600 Ω

Extra load = 900 – 600 = 300 Ω.

Additional power supply required with allowable 50 Ω/volt loading increase, = 300/50 = 6 V.

∴ Minimum power supply required: 24 + 6 = 30 V

PROBLEM 2.4 The raw water pressure is to be measured with a pressure transmitter which is located 10 m below the waterline.

(a) What is the absolute error and percentage error if the waterline pressure is 2.5 kg/cm^2 and the transmitter is calibrated for 0–5 kg/cm^2.

(b) How to permanently correct the error?

Solution:

(a) Range of the transmitter: 0–5 kg/cm^2

Instantaneous line pressure: 2.5 kg/cm^2

As the transmitter is located 10 m below the raw waterline, the transmitter will give more output because of the additional water head of 10 m. The scheme is represented in Figure 2.57.

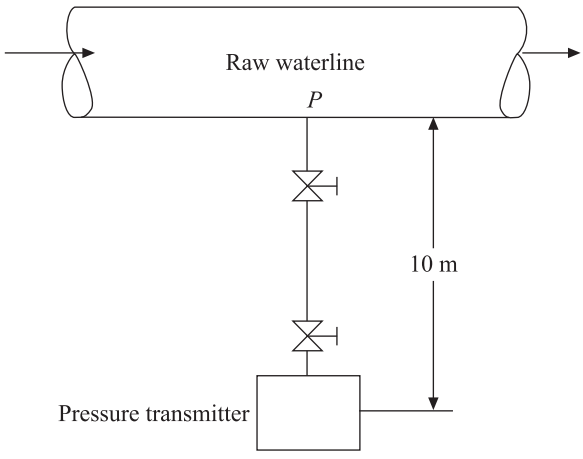


Figure 2.57 Schematic diagram for Problem 2.4.

Pressure exerted on the transmitter $P_T = P + 10$ m

10 m water head = 1 kg/cm^2

$P = 2.5$ kg/cm^2

$\therefore$ $P_T = 2.5 + 1 = 3.5$ kg/cm^2

Absolute error = 3.5 – 2.5 = 1 kg/cm^2

$$\text{Percentage error} = \frac{\text{Absolute error}}{\text{Range}} \times 100$$

$$= \frac{1}{5} \times 100 = 20\%$$

(b) To correct the error permanently, zero suppression of the transmitter to the extent of 1 kg/cm^2 is necessary. When raw water pressure is 0, the output of the transmitter will be equivalent to 0 input though the 10 m water head (i.e 1 kg/cm^2) is existing. Similarly the span can be extended to 6 kg/cm^2 to give the maximum output which will correspond to 5 kg/cm^2 pressure in the raw water line.

PROBLEM 2.5 A two-wire 4–20 mA pressure transmitter of range 0–2 kg/cm^2 is used for measuring the level of water in a deaerator tank. The space above the water is filled with water vapour of 1kg/cm^2 pressure.

(a) Calculate the output of the transmitter if the water level in the tank is 5 m when the pressure transmitter is installed
  (i) Just at the bottom of the tank
  (ii) 5 m below the bottom of the tank
  (iii) 5 m above the bottom of the tank.

(b) If the vapour pressure is brought to 0.5 kg/cm^2 and the transmitter at 5 m below the tank gives an output of 18 mA, calculate the following
  (i) Water level in the tank
  (ii) Current output with the transmitter just at the bottom of the tank
  (iii) Current output with the transmitter 5 m above the bottom of the rank.

Solution: (Refer to Figure 2.58)

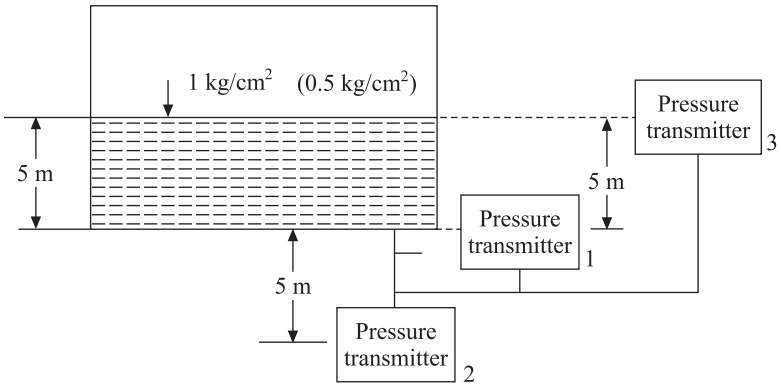


Figure 2.58 Schematic diagram for Problem 2.5.

(a) Output of the transmitter is 4–20 mA for the range 0–2 kg/cm^2

We know that 1 kg/cm^2 = 10 m water column.

$\therefore$ output corresponding to 0 m water column = 4 mA

and to 20 m water column = 20 mA.

Vapour pressure above the water level = 1 kg/cm^2

(i) Water level in the tank = 5 m

Pressure transmitter location: Just at the bottom

$\therefore$ Water column applied = 5 m + 1 kg/cm^2 vapour pressure

= 5 m + 10 m = 15 m = 1.5 kg/cm^2

$$\text{output of the transmitter} = \left(\frac{20-4}{2.0}\times 1.5 + 4\right) = 16 \text{ mA}$$

(ii) Water level in the tank = 5 m

Vapour pressure = 1.0 kg/cm^2 = 10 m

Pressure transmitter location: 5 m below bottom of the tank

$\therefore$ Total water column applied = 5 + 10 + 5

= 20 m = 2 kg/cm^2

$$\therefore \quad \text{output of the transmitter} = \left(\frac{20-4}{2.0}\times 2.0 + 4\right) = 20 \text{ mA}.$$

(iii) Pressure transmitter location = 5 m above bottom of the tank.

$\therefore$ Total water column applied = 5 + 10 – 5

= 10 m = 1 kg/cm^2

$$\text{output of the transmitter} = \left(\frac{20-4}{2.0}\times 1 + 4\right) = 12 \text{ mA}$$

(b) Vapour pressure above the water level = 0.5 kg/cm^2

(i) Pressure transmitter location = 5 m below the bottom of the tank.

Transmitter output = 18 mA

Let h be the water level in the tank

Total water column applied = 5 m (0.5 kg/cm^2) + 5 m + h m

= (h + 10) m

$$\text{output of the transmitter} = \left[\frac{20-4}{20}\times (h+10)\right] + 4$$

= 18 mA (given)

Solving for h, $\dfrac{4h+40}{5} + 4 = 18$

$$4h = 90 - 60 \text{ m}$$

$$h = \frac{30}{4} = 7.5 \text{ m}$$

(ii) Pressure transmitter location = Just at the bottom.

$\therefore$ Water column applied = 5 m + 7.5 m

= 12.5 m

$$\text{Output of the transmitter} = \left(\frac{20-4}{20} \times 12.5\right) + 4$$

= 14 mA

(iii) Pressure transmitter location = 5 m above the bottom

$\therefore$ Water column applied = 5 m + 7.5 m – 5 m = 7.5 m

$$\text{Output of the transmitter} = \left(\frac{20-4}{20} \times 7.5\right) + 4$$

= 10 mA

PROBLEM 2.6 A differential pressure transmitter of 1.2 m Wg range is used to measure the boiler water drum level. Lower tapping and higher tapping are taken 60 cm equidistance from the centre of the drum. If the transmitter used is a two-wire 4–20 mA one and the indicator is calibrated for –60 cm to +60 cm water level, answer the following.

(a) Transmitter output at the +30 cm level
(b) Transmitter output at the –30 cm level
(c) What is the level if transmitter output is 12 mA.

(Assume the error caused by density difference between boiler water and condenser water is negligible and the water head produced by steam is also negligible)

Solution: (Refer to Figure 2.59)

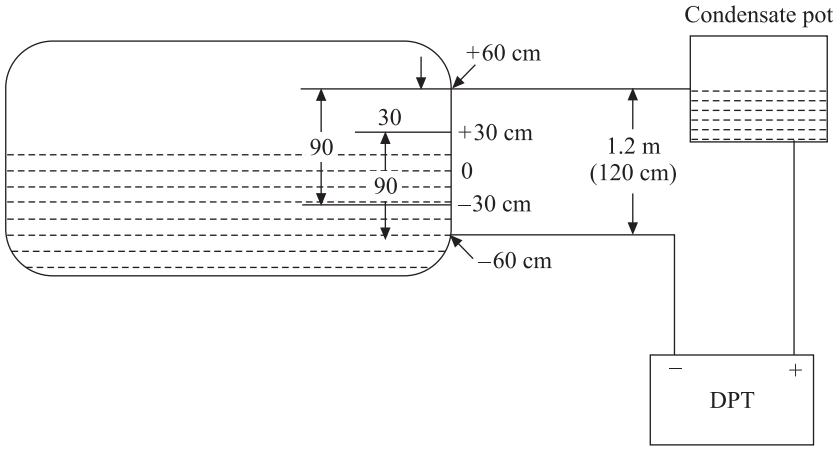


Figure 2.59 Schematic diagram for Problem 2.6.

(a) Water level = +30 cm

$$\text{Transmitter output} = \left[\frac{20-4}{120} \times (120-90) + 4\right] \text{mA}$$

$\therefore$ Full range = 1.2 m = 120 cm and head applied = 120–90

$$= \frac{16}{120} \times 30 + 4 = 8 \text{ mA}$$

(b) Water level = –30 cm

$$\text{Transmitter output} = \left[\frac{20-4}{120} \times (120-30) + 4\right] \text{mA} = 16 \text{ mA}$$

(c) Transmitter output = 12 mA

$$\text{Head applied} = \frac{120}{20-4} \times (12-4) = 60 \text{ cm}$$

Level corresponding to 60 cm head = 0 cm

PROBLEM 2.7 A spray type superheater is supplied with water at 60°C. It is connected to a steamline carrying 200 T/hr of steam at 35 bar. Calculate the amount of water that must be sprayed per hour to maintain steam at 400ºC when the boiler load causes steam to leave at 450ºC.

Solution: Let ω be the rate of water spray required to bring down the steam temperature from 450ºC to 400ºC at 35 bar. We would neglect any pressure drop due to mixing and heat loss to the surroundings. By energy balance of the desuperheater [Refer to Figure 2.60],

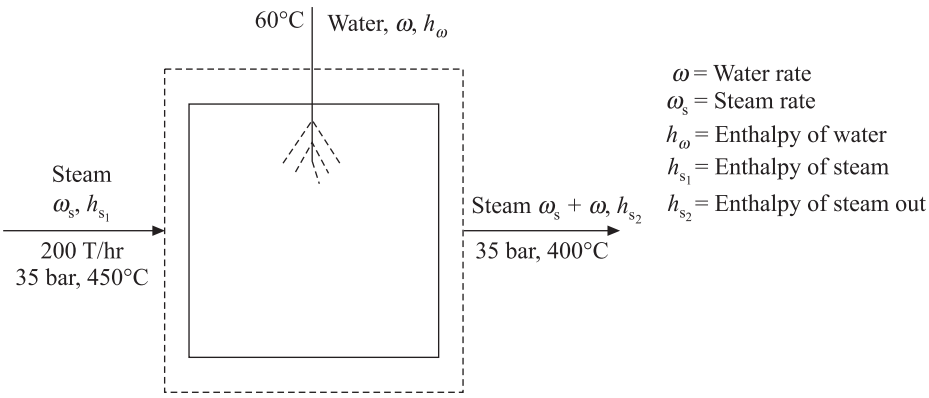


Figure 2.60 Schematic diagram for Problem 2.7.

$$\omega_s h_{s_1} + \omega h_\omega = (\omega_s + \omega) h_{s_2}$$

$$\omega_s (h_{s_1} - h_{s_2}) = \omega (h_{s_2} - h_\omega), \quad \therefore \omega = \frac{\omega_s (h_{s_1} - h_{s_2})}{h_{s_2} - h_\omega}$$

Enthalpies from steam table are:

$$h_{s_1} = 3337.2 \text{ kJ/kg}$$

$$h_{s_2} = 3222.3 \text{ kJ/kg}$$

$$h_\omega = 252 \text{ kJ/kg}$$

$$\therefore \quad \omega = \frac{200(3337.2 - 3222.3)}{3222.3 - 252} = \frac{200 \times 114.9}{2970.3} = 7.733 \text{ T/hr}$$

The amount of water to be sprayed per hour = 7.733 T

EXERCISES

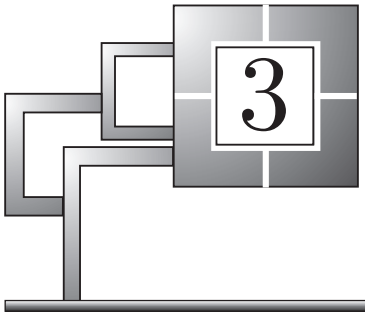
1. What is boiler water circulation? What is the difference between natural circulation and forced circulation?
2. What is circulation ratio? Mention the range in which the circulation ratio should vary.
3. What is blow down? Why is it needed?
4. Why is trisodium phosphate injected into the drum?
5. What do you mean by priming and foaming?
6. What are different methods of superheated steam temperature control?
7. Explain the operation of spray type desuperheater.
8. How is the water level in steam drum controlled?
9. How is three-element level control is superior to both two-element and single-element controls?
10. What is boiler master controller?
11. How is steam bus pressure measured and controlled?
12. What are the basic objectives of feed water treatment?
13. What are the impurities in raw water?
14. Differentiate internal and external means of feed water treatment.
15. What are the basic components of demineralization plant?
16. What do you mean by ion exchange?
17. Name three important measurements carried out to estimate the impurities in steam and feed water.
18. What is pH value? How is it controlled in water?
19. What do you mean by steam purity?
20. Why temperature and pressure corrections are required for steam flow measurement?
21. A boiler drum has a concentration of 1250 ppm. What percentage of water in the boiler drum must be wasted through the blowdown to reduce the concentration to 1000 ppm when the feed water concentration is 11 ppm?
22. A spray type desuperheater is supplied with water at 70ºC. It is connected in a steamline carrying 150 T/hr of steam at 40 bar. Calculate the amount of water that must be sprayed per hour to maintain steam at 450ºC when the boiler load causes steam to leave at 500ºC.

23. What do you mean by 'swelling' and 'shrinking' in a boiler drum?

24. A two-stage superheating and desuperheating system is used for controlling final steam temperature. Calculate the amount of injection water flow through spray-I and spray-II assuming the following (i) steam flow:100 T/hr, (ii) steam temperature before and after spray-I and II are 500ºC, 450ºC, 550ºC and 525ºC respectively. (iii) Cooling coefficient of injection water = 1 kg/°C/Ton of steam.

25. Convert the following pressures into mmWg scale.

(i) 2 bars (ii) 5 kg/cm^2 (iii) 760 mmHg and (iv) 3 atm.



Instrumentation and Control in Air-Fuel Circuit

3.1 AIR-FUEL CIRCUIT

The whole purpose of the steam generator (boiler) is to generate steam out of feed water at the desired rate at the designed temperature and pressure. The heat energy required for this purpose is supplied by burning fuel along with air in the combustion chamber of the boiler. We have seen elaborately the role played by water circuit in Chapter 2. In this chapter we will see the functions of various fuels (solid, liquid and gaseous fuels), the role played by air to burn the fuels, and the various functions of flue gases thus generated. Measurements and controls of various parameters connected with air-fuel circuit will be discussed in this chapter.

Fuels may be in the form of solids (coal, wood, etc), liquids (furnace oil, diesel, LSHS oil, tar, etc) and gases (natural gas, LPG or industrial by product gases). For burning fuels, air (oxygen) is required. Air from atmosphere can be forced into combustion chamber by forced draft (FD) fans or sucked by induced draft (ID) fans. The design of burners will be different for different fuels.

The hot gases generated out of burning give away the heat energy for the purpose of heating feed water and then producing steam. After sufficient heat transfer, the hot gases become flue gases still with some heat content left in them. The heat energy from flue gases is utilized in the economizer to preheat the feed water and then to preheat the combustion air in the air preheater. Once the useful heat energy is recovered from flue gases, they become waste gases. Waste gases are then removed from the boiler with the help of induced draft fan and chimney and let to atmosphere. When the fuel used is in solid form like coal, ash generation will be there after burning. The ash has to be handled separately. The fuel-ash circuit has been already discussed in Chapter 1 with the help of Figure 1.23. When the fuel used is either liquid or gas, they become flue gases after burning along with air. The air-flue gas circuit has also been discussed in Chapter 1 with the help of Figure 1.24. In this chapter we will be discussing the various measurements and controls involving air, fuel, flue gases and waste gases.

3.1.1 Fuels

Fuels can be classified as gaseous, liquid or solid. Gaseous fuel is transported through pipelines. It is easily measurable and controllable. Combustion control along with air ratioed is easily carried out. Liquid fuel is transported through tanks and pipelines. It is being sent to boiler via pipelines and hence easily measureable and controllable. Hence for measurement and control purposes the characteristics of gaseous and liquid fuel are almost similar. The measurement and control treatment for solid fuel has to be different from other fuels. Solid fuel is transported via conveyors and measured with the help of speed and weight measurements together. When solid fuel, say coal, is finely ground and transported in an air stream to the burner, the combustion characteristics will approach those of gaseous and liquid fuels. The state of the fuel is determined by the ratio of hydrogen and carbon present in it. The H/C ratio for coal is generally below 0.07, for fuel oil is around 0.1 and that of natural gas is above 0.3. The molecular weight of carbon is about six times that of hydrogen, and hence the decrease in H/C ratio increases the specific gravity and the density of the fuel.

Solid fuels

Coal, the most commonly used solid fuel, is available in a number of grades. The calorific value of coal varies from around 4000 kcals/kg (lignite coal) to around 8500 kcals/kg (bituminous) depending on the grade. Proximate analysis of coal is done for ranking and ultimate analysis is done for finding out chemical constituents by weight percentage to be used for combustion calculations.

There are three ways of burning coal in a boiler.

1. On a grate burning
2. In suspension burning
3. Fluidised bed burning

1. **On a grate burning** needs no special preparation of coal. It is weighed to know the amount of coal admitted into the boiler, made to flow by gravity to a stoker hopper and from there to the grate.
2. **In suspension burning** coal is finely ground and carried to the combustion chamber with the help of primary air stream. Additional air for complete combustion is supplied as secondary air. Both primary air and secondary air quantities are taken into account for ratio setting with fuel.
3. **Fluidised bed burning** employs adjustable rate feeder to admit coal to the fluidised bed.

Liquid fuels

Fuel oil from the petroleum refining process is the most common liquid fuel. They are easy to handle, easy to measure and easy to control. Fuel oil is normally stored in oil tanks and pumped to the boiler. Atomisation of oil is carried out either by steam or by air. Heavy fuel oil requires some external heating to reduce its viscosity before burning.

Gaseous fuels

Though natural gas is the most used gaseous fuel, gas produced from industries as by-product gases and refinery gas from petroleum refinery units are also used to a great extent. Calorific

value and other physical and chemical properties vary significantly from one gas to another. Gases are supplied through pipelines and directly burned in the boiler. Some installations have provisions to store limited stock in gas holders.

Multifuels

Multifuels can be used in the boiler considering the availability and cost effectiveness. But transportation, storing and burning has to be done as though they were burned alone. Burner designs and combustion control arrangements are to be done independently though the total heat energy supplied by different fuels is taken into account for load sharing purposes.

3.1.2 Combustion Air

Combustion is the process of generating heat energy by combining fuel and air. The flue gas generated after burning the fuel with air is utilized for transferring heat to boiler water to generate steam. For complete combustion to take place, the following conditions are to be satisfied:

(i) Fuel is gasified, pulverized or atomised
(ii) Sufficient combustion air is supplied
(iii) Thorough mixing of fuel and air is done within flammable range
(iv) Temperature above ignition point is available.

The three Ts of combustion are Time, Temperature and Turbulence. Rapid combustion is possible in short period of time at high temperature with very turbulent flame. Turbulence is created for thorough mixing of fuel and air so that the combustion is complete. With complete combustion the flame temperature is expected to be high in less combustion time. Poor mixing of fuel and air may end up with longer time for combustion and lower flame temperature.

Combustion air supply

Combustion air for steam boilers may be supplied by forced draft (pressure fan at inlet), induced draft (suction fan at boiler outlet or stack draft), or a combination of forced and induced draft known as *balanced draft fans*. With balanced draft boilers, a slight negative pressure is maintained in the furnace. In our discussions we assume that forced draft fan is the source of combustion air supply. The forced draft fan draws in air from atmosphere and delivers it through air ducts to the air inlet of an air preheater. The air is preheated in the air preheater by taking heat energy from the flue gas coming out of economiser. From the preheater, air is delivered through air ducts or pipes to the combustion equipment. The fans used may be either centrifugal or axial. There are two common methods of controlling the output of fans: damper control and variable-speed control. In damper control, a damper (butterfly valve) is used to control the flow of air by regulating the flow area according to the load. Dampers are usually put on the outlet side of the fan, although dampers at inlet to the fan are sometimes used. In variable-speed control, the fan motor speed is controlled to control the flow of air. Variable speed control has the advantage of less power consumption and is the most efficient method for fan control. The major disadvantage of variable-speed control is the higher capital costs than damper control.

Theoretical air requirement

The actual chemical process during burning of a fuel is the oxidation of the hydrogen and carbon in fuel by combining with oxygen from air. The nitrogen in the air and other non-combustibles in

the fuel will be passing through the process without undergoing any chemical change. They only carry away some useful heat along with them while exiting from the boiler. For any fuel, a precise amount of combustion air is needed to supply oxygen for complete combustion. With fuel analysis, one can calculate the theoretical amount of air using combustion chemistry formulae. The combustion is called *perfect combustion* if the fuel is completely burned with exact quantity of oxygen. The quantity of air which provides such quantity of oxygen is called *theoretical air*. In other words, the amount of air which is used to supply oxygen just sufficient to unite with all the fuel atoms to ensure perfect combustion is called *theoretical air*.

Excess air requirement

Perfect combustion is not practical at all. One cannot make sure that there will be an oxygen atom near fuel atom always. Best achieveable conditions of turbulence also cannot satisfy for perfect combustion. With only theoretical air supplied, there will always be some fuel atoms which do not find their matching oxygen atoms nearby. Then there is a possibility of incomplete combustion and hence heat energy left in the unburned fuel would be lost. To ensure complete combustion, additional amount of combustion air is added so that all fuel atoms find oxygen atoms for burning. The additional amount of combustion air required for complete combustion than that of theoretical air is called *excess air*. Excess air plus theoretical air is known as *total air*. This means some of the oxygen will leave the boiler along with flue gas unused. Too much of excess air is also not recommended because of the reduction in flame temperature and hence heat transfer rate. The oxygen percentage in the flue gas is an indicator of excess air. Less air leaves some portion of fuel unburned and more air means heat loss through flue gases. The furnace has to be operated at an optimum level taking care of the above factors with correct amount of excess air. Excess air amount is decided by the type of fuel used, burner design, fuel characteristics and other factors. Table 3.1 shows an approximate amount of excess air required for different fuels.

Table 3.1 Excess air required for different fuels

Fuel	% oxygen in flue gas	% excess air minimum
Natural gas	1.5 to 3	7–15
Fuel oil	0.6 to 3	3–15
Coal	4.0 to 6.5	25–40

3.1.3 Flue Gases

Oxidation of the combustible elements of the fuel at high temperature with release of heat is called *combustion*. The hot gaseous mixture formed out of combustion is called *flue gases*.

Products of combustion

The combustible elements in fuel are carbon and hydrogen in addition to small percentage of sulphur. The basic chemical equations for complete combustion are:

$$C + O_2 \rightarrow CO_2$$

$$2H_2 + O_2 \rightarrow 2H_2O$$

$$S + O_2 \rightarrow SO_2$$

When insufficient oxygen is present, the carbon will be burned incompletely with the formation of carbon monoxide

$$2C + O_2 \rightarrow 2CO$$

In addition the nitrogen present in the air and the excess oxygen will also be present in the flue gas. In general we may conclude that the products of combustion (constituents of flue gas) will contain the following:

Carbon dioxide (CO_2)
Water vapour (H_2O)
Sulphur dioxide (SO_2)
Carbon monoxide (CO)
Nitrogen (N_2)
Oxygen (O_2)
Others like ash, water, NO_X, SO_X, etc.

The analysis of above constituents in the flue gas helps one for the following:

1. To calculate boiler efficiency
2. To ensure proper combustion and make combustion calculations
3. To find out excess air component and adjust as required.
4. To control the pollution effluents and satisfy the regulatory norms of the concerned authorities

Flow of flue gases

The hot gaseous mixture (flue gases) after combustion is the main heat source for transferring heat energy to the boiler water. As we have already seen, the water gets heated up to form saturated steam first and then to superheated steam. After the main heat transfer has taken place, flue gases are still left with some more heat energy. Further heat recovery is done to preheat the boiler feed water in the economiser and the combustion air in the air preheater. The flue gases coming out of the air preheater after giving away the heat energy as above is called *waste gases*.

3.1.4 Waste Gases

Waste gases are the flue gases minus the heat energy utilized in the boiler, economiser and preheater. As these gases have no more utility, they have to be taken out of the boiler house and let into atmosphere. Induced draft (ID) fan and chimney help to produce vacuum and suck the waste gases and let them into atmosphere. Care has to be taken to follow the rules and regulations of the pollution regulatory bodies before letting them into atmosphere. Failure to comply with current emissions regulations can be as costly as lost utilities. Government mandates enforced by fines, threat of closure, or imprisonment will usually provide sufficient incentive to comply with the regulations and modernize controls if necessary. Improved combustion efficiency reduces unwanted combustion by-products. By accurately controlling oxygen, fuel flow, and stack temperature one will see reductions in plant emissions.

Analysis of O_2, CO and CO_2 are carried out in addition to smoke density and dust analyses. The discharge of smoke to the atmosphere is an unnecessary evil. The effects of smoke may be considered under three headings, namely, 1) effect on health, 2) financial loss due to incomplete

combustion and 3) effect on standard of living. Colour of the smoke (white to black) gives some idea about the smoke density and the combustion completeness. Furnaces burning coal in suspension (pulverised coal burners and spreader stokers) will always throw out dust in the form of fly-ash.

In modern power plants, analysis has moved out of the laboratory and become on-line measurement. The new generation of on-line analysers are of prototype which eliminates both the transportation lag and the interference with sample integrity. The demand for more and better analysers is reinforced by the growing concern about environmental pollution and the associated need to enforce safety standards by detecting the concentrations of various pollutants. The analysers required for safety and environmental control purposes include the following.

1. CO_2 in the waste gas
2. CO in the waste gas
3. NO_X analysis
4. SO_X analysis
5. Dust monitor
6. Smoke detector

3.2 MEASUREMENTS IN AIR-FUEL CIRCUIT

The following measurements are needed in air-fuel circuit.

1. **Measurement of flow/quantity:** The following come under the measurement of flow quantity:
   - Solid fuel flow (coal)
   - Liquid fuel flow (oil)
   - Fuel gas flow
   - Combustion air flow.
2. **Measurement of pressures:** The following come under the measurement of pressure:
   - Fuel oil pressure
   - Atomised steam pressure
   - Fuel gas pressure
   - Combustion air pressure
   - Flue gas pressures
   - Waste gas pressures
   - Furnace draft.
3. **Measurement of temperatures:** The following come under the measurement of temperatures:
   - Fuel oil temperature
   - Atomised steam temperature
   - Combustion air temperature
   - Primary and secondary air temperature
   - Flue gas temperature

- Waste gas temperature
- Flame temperature

4. **Measurement of levels:** The following come under the measurement of level:
   - Coal bunker/hopper level
   - Oil tank level
   - Gas holder level

Analysis of fuel gas, flue gas and waste gas, smoke and dust indications etc. will be covered separately in the end of the chapter.

3.2.1 Measurement of Flow/Quantity

Coal quantity

Measurement of coal which is fed to boiler as a fuel has to be done for calculation of boiler efficiency. Sometimes this signal can be beneficially used for combustion control purpose also. It is not that straight measurement as it is done for liquid or gaseous fuel. There are three common methods available.

(a) Indirect measurement from bunker level: Coal is delivered to the power plant by means of trucks or rail wagons. In some cases it is delivered from ship through belt conveyors. The user must have sufficient space and mechanical equipment for storing and handling prior to use. The coal is then transferred to coal 'bunkers' from coal storage. These bunkers, or short-term storage bins, are located at an elevation that allows the coal to feed to the boiler system by gravity. By recording the bunker level at regular intervals (say every half an hour) and converting the level difference into volume one may be able to get the average volume flow rate. Totalling can be done at the end of the day's operation and average flow rate for the day can be found out. Though such measurements cannot be used for continuous control purposes, the information can be very well used for boiler efficiency calculations.

(b) Measurement using load cells: The coal can be fed to hoppers fitted with load cells and then fed to boiler system. The hopper will be filled, the weight measurement is taken and then emptied to the feeding conveyor. This cycle can be continuously done and the weight measured is divided by the cycle time to get the average feed rate. This way of measuring is more accurate compared to the one by measuring the bunker level.

(c) Measurement by belt weighing: The flow rate of coal can be measured when it is fed to the boiler system via belt conveyor. Load cell arrangement can be used to measure the weight of the coal in the belt between two rollers which are designed to float for making the measurement possible. The conveyor speed can be measured and used for calculating flow-rate. The feed rate of all belt weighing feeders is a function of the belt speed and the belt load. Belt speed is normally expressed in terms of metre per minute, while belt load is defined as kilogram per metre of belt.

$$\text{Feed rate} = \text{Belt speed} \times \text{Belt load.}$$

In case of constant speed belt feeders, the rate is directly proportional to belt load.

Liquid flow measurement

Furnace oil or tar oil is used as fuel in the boilers. Oil flow rate can be measured by any of the following means in a steam power plant.

(a) Positive displacement type meters
(b) Rotameters
(c) Electromagnetic flow meters
(d) Variable head type flow meters (orifice type normally)
(e) Oval-gear meters
(f) Turbine flow meters.

As the details of the above flow metres are available in any standard instrumentation/process measurements books, they are not discussed here.

Flow measurement of gaseous fuels and combustion air

Flow measurements in gas lines and combustion air lines are done mainly for combustion control purposes. Gas flow measurements are also used for totalising before using them for accounting purposes. As gas as well as air are compressible fluids and their density vary with temperature and pressure, they are measured with reference to either normal temperature and pressure (NTP) or standard temperature and pressure (STP). Their units accordingly will be either Nm^3/hr or Sm^3/hr.

Variable head type flow meters with different sensors like orifice plate, venturi tube, flow nozzle, Dall tubes etc. are used for measuring gas and air flow rates in thermal power plants. Differential pressure transmitters with/without square root extractors are used for converting the head into standard electrical signal (4–20 mA). But for installation the other details are similar to what has been discussed for water and steam flow measurements in Chapter 2.

The installation details to be discussed below will be same for both gas and air flow measurements. Only flow ranges and location of the sensor will vary as per design. If the differential pressure transmitter is to be located below the level of the main line or pipeline in which the orifice is installed, the pressure pipe should be laid as follows. The pressure pipe must be raised above 0.5 m vertically up from the orifice as illustrated in Figure 3.1 and then continuously fall at the slope of not less than 1:10 to the transmitter. If the orifice is located at a considerable distance away, the arrangement shown in dotted lines hold good.

If the differential pressure transmitter is to be located above the pipeline in which the orifice is installed, the pressure pipe should be laid as follows. The impulse pipe is continuously raised at a slope of not less than 1:10 from orifice to the transmitter as shown in Figure 3.2. The pressure pipes should be fitted with blow off drains to be drained at suitable intervals as shown in Figure 3.1. For distant orifice, the arrangement is shown in dotted lines.

The idea of lifting up the pressure lines initially is to make the dust particles or water drops carried by the medium to fall into the main line instead of being carried over and choking the pressure lines, which are smaller in size compared to the main line. The drain valve installed in the main line can be suitably drained at regular intervals. The drain valves or blow off valves installed near the transmitter is used to drain condensed water, dust and mud collected.

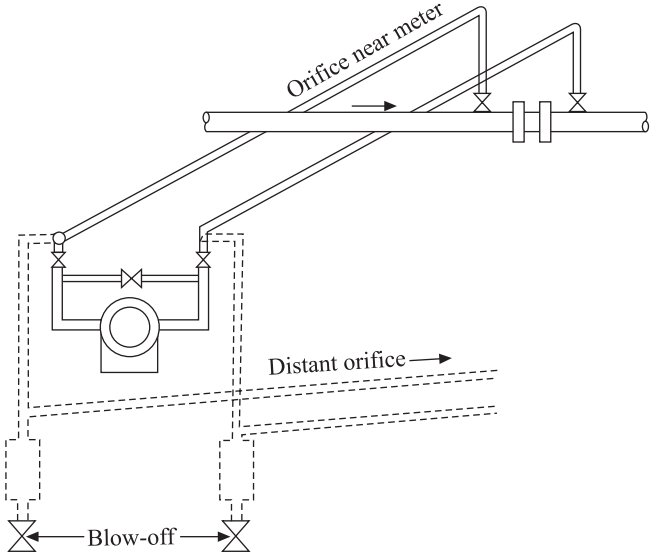


Figure 3.1 Pressure connections to meter below orifice for air and gases.

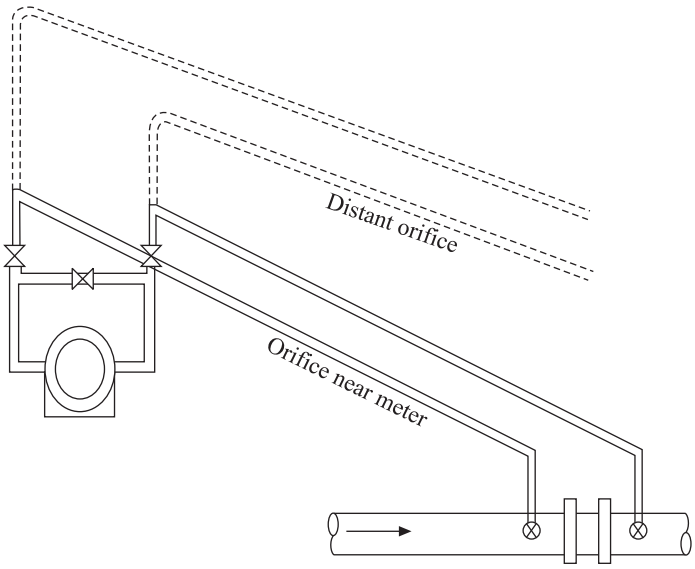


Figure 3.2 Pressure connections to meter above orifice for air and gases.

3.2.2 Measurement of Pressures

Steam and oil pressure

Fuel oil pressure and atomised steam pressure are measured using Bourdon gauges for local indications. For transmission purposes electronic transmitters (either strain gauge type or capacitance type) are used. The range of the pressure measurement may be from 0 to 20 kg/cm^2.

While measuring oil pressure, the oil may get solidified in the pressure signal pipelines unless the temperature is maintained. For this purpose steam tracing outside the signal pipelines are always done.

Fuel gas and combustion air pressure

Fuel gas and combustion air pressures are in the order of 0 to 2000 mmWg. Hence either membrane type or capsule type sensors are used both for local indication and for transmission. The following are some of the sensing points.

- Fuel gas main line pressure
- Pressure before and after pressure control valve
- FD fan outlet pressure
- Pressure before and after air preheater
- Pressure just before burner

Flue gas and waste gas pressures

The pressure of the flue gas may vary from about 50 mmWg to about – 100 mmWg while travelling from combustion chamber to economiser to air preheater and to atmosphere through ID fan and chimney. The positive pressure is due to the combustion air pressure and gas pressure at the entering point. The negative pressure is generated by induced draft fan and chimney to make the flue gas flow possible. The various measuring locations are listed below:

- Combustion chamber pressure
- Pressure before and after economiser
- Pressure before and after air preheater
- Pressure before and after ID fan
- Pressure before chimney.

Differential pressure sensors using diaphragm or membrane are employed for measuring such low pressures. Both direct reading and transmission type are possible.

Furnace draft

Basically air and fuel flow into the furnace (combustion chamber) and flue gas flows out. The force driving this flow is the differential pressure between the gases inside the furnace and those outside the furnace. Furnace pressure is commonly referred to as draft or draft pressure. The draft is maintained slightly negative to prevent the combustion products and ash from being discharged from the furnace into surrounding areas through inspection ports, doors, feeders etc. The range of the furnace pressure will be around ±20 mmWg. The location of the furnace pressure tapping is very essential to get the true representative sample.

Figure 3.3 demonstrates the choice of pressure tap locations for measuring furnace draft. The pressure connection on most boilers is located on the front (1), side (2), or roof (3) of the furnace as shown. Although the measurements at these three locations would be for the same furnace chamber of a particular boiler, the measurement values would differ due to the differing stack or chimney effects. The measurement in the roof of the furnace will be the highest value. Since it is necessary to have negative pressure at all points, the value at the furnace roof becomes the controlling factor in determining the desired set point for the control of set draft. Because of the very low pressure involved, the pressure connection should be large enough so that even the slight changes in the furnace draft can be very quickly felt by the measuring instrument. A general

arrangement is shown in Figure 3.4. It is recommended that the furnace pressure transmitter connections to the boiler furnace be made with a pipe of at least 25 mm diameter because of low pressure involved. It is also better to keep the distance as minimum as possible (better if it is less than 5 metres). Differential pressure transmitter of about ±20 mmWg range is used for this measurement. To have better sensitivity the diaphragm used will be of larger type with one side opened to the atmosphere and the other side connected to furnace.

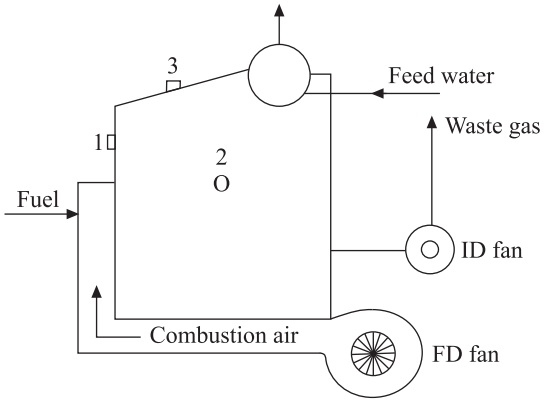


Figure 3.3 Alternate furnace draft pressure connections.

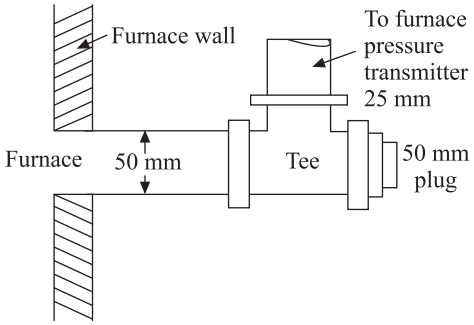


Figure 3.4 Pressure tap for furnace draft.

3.2.3 Measurement of Temperatures

The temperatures of operation in the air-fuel circuit vary almost from room temperature to about 1200ºC. Combustion air temperature at the inlet of air preheater may be around room temperature. The highest flue gas temperature at the heat transfer to superheater point may touch around 1200ºC.

Fuel oil temperature (about 100ºC), combustion air temperatures at various points, flue gas temperatures after economiser and before air preheater, waste gas temperature (after air preheater, before and after ID fan, inlet to chimney) etc. can be very well measured with RTDs (Pt100 in general). Atomised steam temperature can either be measured with RTD or with iron-constantan thermocouple. Primary and secondary air temperatures can be measured either with RTDs or with iron-constantan thermocouples. Flue gas temperatures from combustion chamber to input of economiser are measured generally using nickel chrome-nickel thermocouple (called in short *chromel–alumel thermocouple*). Figure 2.12 may be referred to for some commercial types of RTDs and thermocouples which are used in power plants.

Liquid-in-glass thermometers and vapour-pressure thermometers are normally used wherever local indications are sought for. Radiation pyrometers and infrared pyrometers with cooling arrangements for electronic circuits are employed for measuring flame temperatures.

3.2.4 Measurement of Level

Level measurements in air-fuel circuit are necessary, mainly at the following three equipment.

1 Coal bunker/hopper to know the coal quantity available at any point of time.
2 Oil tank to know the position of oil fuel available.
3 Gas holder to know the availability of gaseous fuel.

Coal bunker/hopper level

The measurement probes may be of side-mounted or top-mounted types. The types of instruments used are mentioned below without elaborating their operations.

1. Radiation-type instruments (single source and multiple source ones)
2. Ultrasonic level transmitters (used both for continuous measurement and as level switches)
3. Microwave level transmitters
4. Optical level devices
5. Radar level transmitters
6. Laser level devices
7. Level switches using the following devices:
   (a) Rotating paddle switches
   (b) Vibration damping switches
   (c) Microwave level switches
   (d) Field-effect level switches.

The working details of all the above solid-level instruments are available in standard books meant for industrial instrumentation and process measurements.

Oil tank level

From the oil refinery, the fuel oil is delivered to the storage tanks. From the storage tanks the oil may be taken directly to the fuel preparation unit, or it may be transferred to a smaller tank called a *day tank*. Fuel oil pumps are used to pump the oil from the tank to the burners. It is very important to know the oil level either in the storage tank or in the day tank for day to day operations of the thermal power plants. Assuming the oil is in liquid state, the level can be observed locally using gage glass. Pressure measured at the bottom of the tank can be converted into level knowing the density.

Gas holder level

The gas holder is intermediate equipment between the gas sources and the consuming unit. The gas fuel may be the refinery gas or the by-product gases or the natural gas. The thermal power plant operators expect this fuel to be supplied in a pipeline at constant pressure so that the combustion control can be exercised comfortably in the boiler. For this purpose the gas from any source is first supplied to a gas holder whose drum/disk is designed for the desired pressure. When more and more gas is pumped into the gas holder, the pressure will rise and hence the drum/disk will get lifted accordingly. The position of the drum can be taken as the gas level in the holder. The position can be measured by a chain and counter-weight arrangement connected to a large dial for local indication. The chain movement can be connected through wheel and gear arrangement to a transmitter for transmitting signal to remote places.

The simplified arrangement is shown in Figure 3.5. For local indication, a vertical dial and a pointer fixed to counter-weight is provided. The dial reading will be in the reverse direction. When the gas holder is full the pointer is in the bottom of the scale and vice versa. For remote transmission, the shaft of the pulley is connected to a transmitter which can convert the rotary motion into a standard electrical signal. A small gear box and a rotary transmitter will do the function. Synchros can be used instead of electronic transmitters in small power stations.

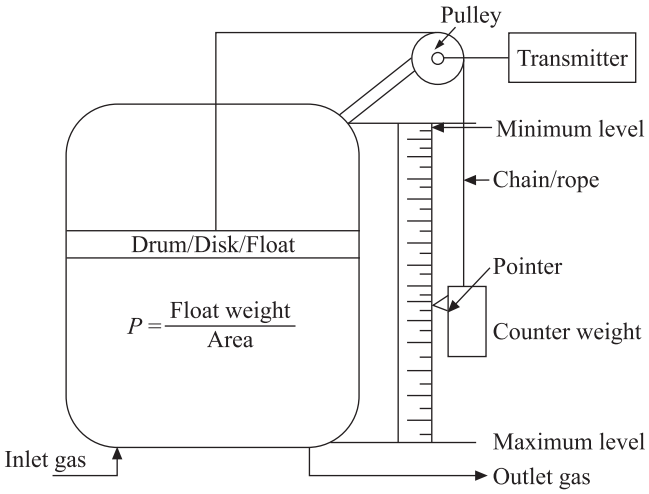


Figure 3.5 Gas holder level measurement.

3.3 CONTROLS IN AIR-FUEL CIRCUIT

The controls in the air-fuel circuit are necessary to improve combustion efficiency. Reduction in fuel consumption will be followed by reducing excess air. Two important controls in the air-fuel circuit are:

1. Combustion control
2. Furnace draft control

3.3.1 Combustion Control

Steam pressure is the key variable that indicates the state of balance between the supply and demand for steam. If supply exceeds demand, the pressure will rise. Conversely, if demand exceeds supply, the pressure will fall. The pressure controller with main header pressure as controlled variable, manipulates the firing rate demand to control steam pressure at the desired set point. Alternately steam flow, generator current or some other quantity that is affected by load, could possibly be used, but steam pressure control is the common practice.

The term 'plant master' is most applicable to the situation in which more than one boiler supplies a common steam header. In this case there are multiple boiler masters but only one plant master. The plant master generates the master firing rate demand signal that drives the individual boilers in parallel. With several boilers supplying a common header in parallel, it is generally desirable to provide a way to adjust the load distribution among the boilers. Depending on the load and the performance of the individual boilers, the most efficient operation may be achieved with some boilers shut down, some boilers base loaded (constant firing rate), and the remaining boilers allowed to swing with the load (variable firing rate).

Our further discussions will be on combustion control of an individual boiler which receives firing rate demand from plant master through boiler master control. The primary function of combustion control is to deliver fuel and air to the burner at a rate that satisfies the firing rate

demand and at a mixture (fuel/air ratio) that provides safe and efficient combustion. Insufficient air flow wastes fuel due to incomplete combustion and can cause an accumulation of combustible gases that can be ignited explosively by hot spots in the furnace. Too much air flow wastes fuel by heating up the stack excessively. Combustion controls are designed to achieve the optimum air/fuel ratio, while guarding against the hazard caused by insufficient air flow.

The flow of fuel, air or flue gas in the air-fuel circuit must vary if the rate of combustion varies. Because of variable demand, which is the common experience, the heat energy originated by combustion is wanted at varying rates of production. It is in the air fuel loop that the energy is originated as heat; hence control for variable rate of energy production begins in this part of the plant. In general the combustion control system seeks to attain the following objectives:

1. Regulate input of heat energy to the plant equipment so that it will be always equal to the plant needs, but not in excess.
2. Maintain high efficiency of combustion at all rates.
3. Be sufficiently sensitive, so that the thermal state of the plant equipment does not fluctuate. Only the rate of energy flow should vary.
4. Safety to be maintained by guarding against the hazard caused by insufficient air flow.

The control of combustion for variable load needs to adjust the fuel input proportional to the load. This must be accompanied by a change in air flow to the combustion equipment so that the most efficient air-fuel ratio will be maintained at all loads. Some secondary features usually found to be desirable are the maintenance of 'balanced draft', and the 'apportionment' of load (load sharing) among boilers operating in parallel on the same steam main.

The primary boiler fuels are gas, oil and coal. The control of gas and oil fuels are simple and easy as because they are easily measurable. The control with coal as fuel is little complicated because of the measurement problem. We will discuss in the following pages the combustion controls adapted for various fuels.

Combustion control with gaseous fuel

Fuel control: It is a simple feedback control loop with firing rate demand (fuel demand) signal from boiler master controller as set point. The gas flow is measured and square rooted and given as actual value to the controller. The controller output is utilized to open/close the flow control valve in the gas line to increase/decrease the amount of gas to the boiler satisfying the fuel demand (Refer to Figure 3.6).

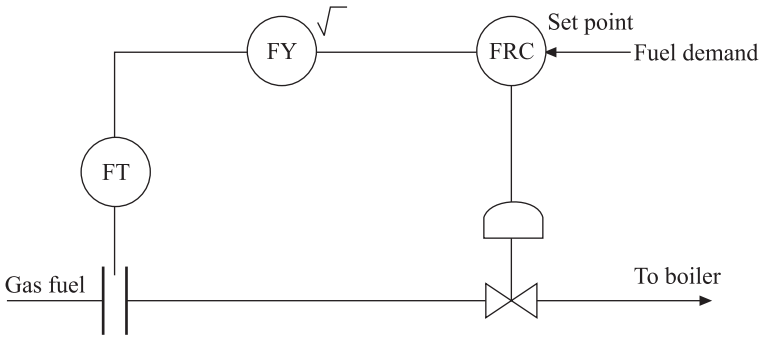


Figure 3.6 Gas fuel control.

Combustion control–Single-point positioning: The simplest combustion control system which can be applied to boilers is single-point positioning, often referred to as 'jackshaft' control. The fuel controller output operates the final control element which in turn opens/closes the control valve in the fuel line. The mechanical lever/link between the final control element and the control valve will have further mechanical link to the combustion air flow damper. Both fuel valve and air damper are operated by the same controller and the final control element. A single-point positioning system uses a mechanical linkage to manipulate the fuel control valve and the combustion air flow damper in a fixed relationship. The alignment of the fuel valve and air damper positioners is critical for this type of control. Because fuel valves and air dampers have different flow characteristics, it is necessary to linearise these flow characteristics. The air/fuel ratio required for proper combustion is fixed through this linkage only. The position of the fuel control valve and the combustion air flow damper are connected together in a fixed relationship and move in unison to the demands of the controller.

Combustion control–Parallel positioning: The parallel-positioning control system uses a similar strategy as single-point positioning for combustion control. However, parallel positioning refers to two outputs used in parallel to control the fuel valve and the air damper. Instead of adjusting air/fuel ratio through mechanical links in single-point positioning control, air damper valve is operated by a signal generated via manual setter. The same signal from the controller is given in two paths. Figure 3.7 shows the parallel-positioning control scheme. The two outputs go to the fuel valve and the air damper. The jackshaft used in single-point positioning is replaced by the function block before air flow actuator with a manual air/fuel ratio set.

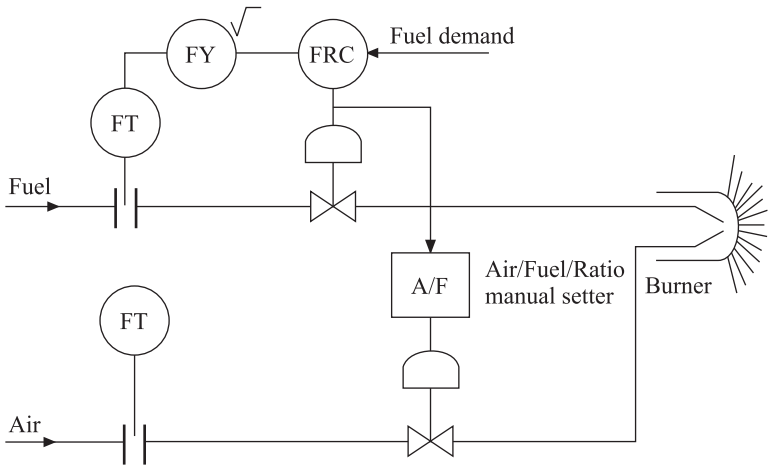


Figure 3.7 Combustion control–Parallel positioning.

Both single-point positioning and parallel positioning do not make use of the air flow measurement in the control. Air pressure and temperature variations cannot be taken care of by the above systems. This weakness can be overcome by including measurements of fuel and air flow in the control strategy.

Combustion control: Series fuel-air ratio control: To overcome the difficulties faced in single-point positioning and parallel-positioning control, the flow measurements of fuel and air are done and made use of in series fuel air ratio control. As a first step the fuel flow is controlled as per firing rate demand (Refer to Figure 3.6). The fuel flow signal is given to air flow control through ratio station where the required air-fuel ratio is set manually. The output of ratio station becomes set point to air flow controller which takes feedback from air flow transmitter. This type of control strategy is also called 'fuel leading air' control. Fuel varies first as per firing rate demand and this change causes air to vary as per ratio set. Instead it is also possible to have 'air leading fuel' control strategy. Here air varies first as per the firing rate demand and this change causes fuel to vary according to ratio set. Both strategies have their own advantages and disadvantages which we will discuss in detail under cross limited control strategy. Refer to Figure 3.8 for series fuel-air ratio control with fuel leading air (air leading fuel is possible just interchanging the air and fuel and the ratio set).

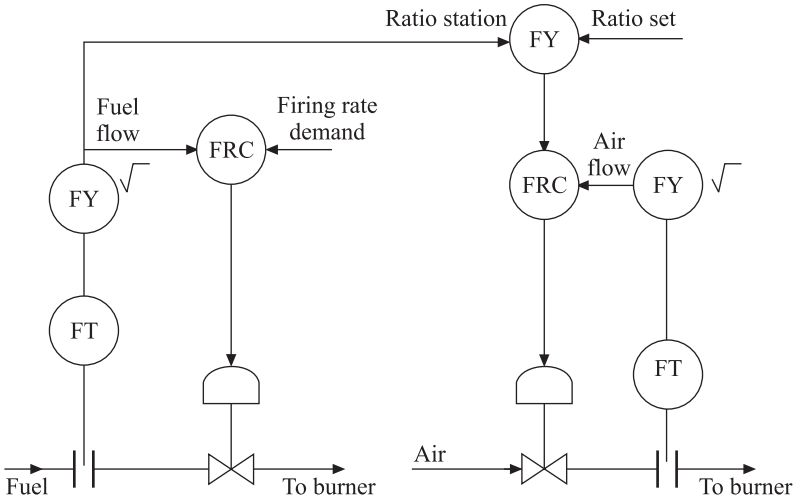


Figure 3.8 Metered series air-fuel ratio control.

Combustion control: Parallel air-fuel ratio control: As a general rule (except in the case of very slow-changing boiler loads), fuel and air should be controlled parallel rather than in series. This is necessary because a lag of only few seconds in measurement and transmission will seriously upset combustion conditions in a series system. This can result in alternating periods of excess and deficient combustion air. Also the interaction between air and fuel loops is to be taken into account. The effect of interaction and disturbances in the fuel and air control loops can be minimized by the use of parallel fuel and air control. Here the firing rate demand is directly given as set point to fuel controller and is given through ratio station to air controller simultaneously. The fuel and air vary simultaneously as per firing rate demand. The control schematic is shown in Figure 3.9 which is self-explanatory.

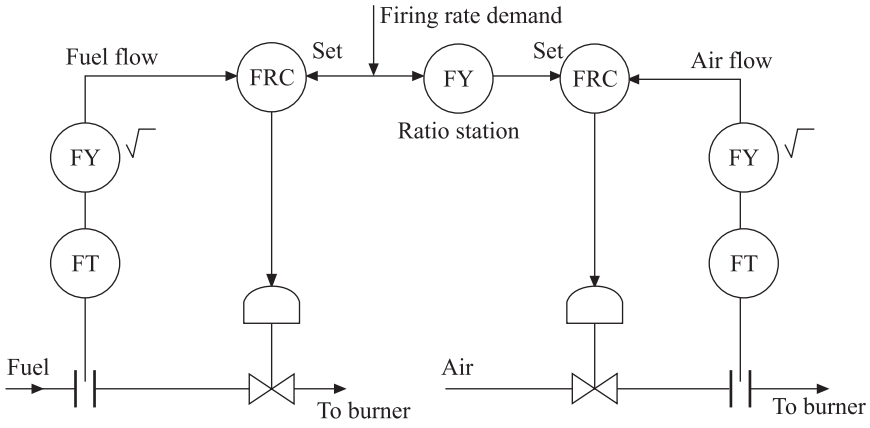


Figure 3.9 Metered parallel air-fuel ratio control.

Combustion control: Metered cross-limited air-fuel ratio control: The fully-metered, cross-limited control scheme is sometimes referred to as the standard control arrangement. This control arrangement includes active safety constraints. The benefits of this control scheme are:

(a) Compensates for fuel and combustion air flow variations
(b) Provides active safety constraints to prevent hazardous conditions

Three signals are used to balance the fuel-air mixture. These are firing rate demand through steam header pressure, the fuel flow, and the air flow. The combustion controls consist of fuel flow and air flow control loops that are driven by the firing rate demand signal. The block diagram of this control arrangement is shown in Figure 3.10.

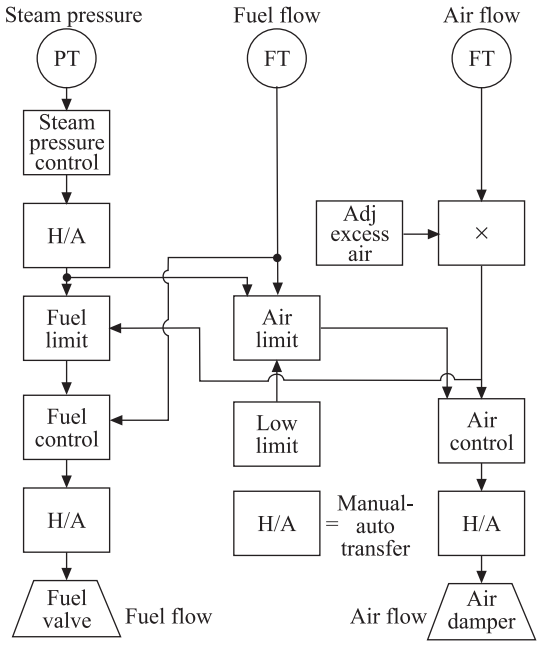


Figure 3.10 Metered cross-limited boiler control system.

'Cross-limited', 'lead-lag', 'self-linearising' and 'flow-tieback' are different names given to the same control strategy.

Maintaining the correct fuel-air ratio also contributes to limiting the fuel rate to available air and limiting air minimum and maximum to fuel flow, air leading fuel on load increase and air lagging fuel on load decrease. This arrangement also protects against a fan failure or a sticking fuel valve. Though not normally furnished in smaller boilers, the following limiting actions are desirable for safety reasons.

(a) Limiting fuel to available air flow.
(b) Minimum limiting of air flow to match minimum fuel flow or to other safe minimum limit.
(c) Limiting minimum fuel flow to maintain stable flame.

The metered-parallel cross-limited air-fuel ratio control system shown in Figure 3.11 illustrates the above. The block diagram shown in Figure 3.10 is redrawn as a control system equivalent in Figure 3.11. The simple description of the working of the system with reference to Figure 3.11 is given.

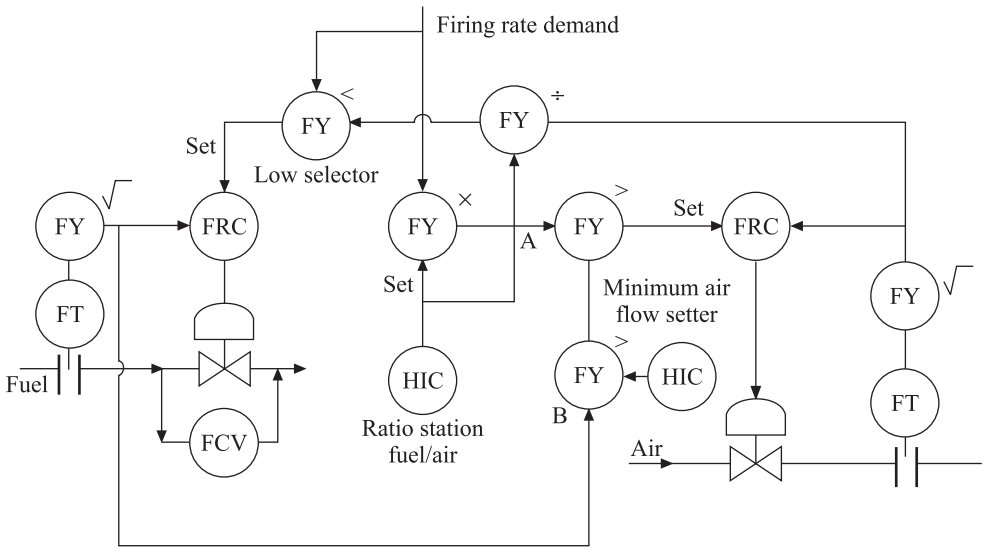


Figure 3.11 Metered parallel cross-limited air-fuel ratio control.

If the actual air flow decreases below firing rate demand, then the actual airflow signal is selected to become the fuel demand by low selector $FY^{<}$.

If the fuel flow is at minimum and firing rate demand further decreases, actual fuel flow becomes air flow demand, because $FY - A^{>}$ will select the fuel signal if it is greater than firing rate demand signal. A manual air flow minimum is also available to come into use through $FY - B^{>}$, such that if fuel flow signal drops below the HIC setting, this manual setting will become the air flow set point.

Fuel is minimum limited by separate direct acting pressure or flow regulator FCV to maintain stable flame.

These high and low selectors provide the so called cross limited parallel controlling system. When the firing rate demand increases, the high selector provides it as an air flow set point while the low selector transmits the air flow process variable as the fuel flow set point. Air flow therefore starts to increase immediately; fuel flow rises only after the air flow responds. When the firing rate demand decreases, the low selector provides it as the fuel flow set point while the high selector transmits the fuel flow process variable as the air flow set point. Fuel flow starts decreasing immediately; air flow drops only after fuel flow responds. Likewise it protects from air flow disturbance to lower side, fan failure and fuel valve chokage etc. Thus fuel rich condition is always prevented (safety point of view).

Combustion control with liquid fuel

Most of the combustion control systems discussed for gaseous fuel hold good for liquid fuel also. Only the measurement techniques of fuel may vary. Vapourising or atomising of oil is required for proper mixing with combustion air for complete combustion.

Steam atomisation control: The main difference in oil burners is the method of preparing the fuel for close mixing with air. This can be done by vapourising or by atomizing. The commonly used way is steam atomizing. This can be accomplished by mixing the oil with a steam jet in a steam atomizer. Proper atomization at the burner and therefore complete combustion will be achieved only if oil is kept at constant pressure and viscosity. When heavy residual oil is burned, it must be continuously circulated past the burner and back. The difference between the readings of inlet and return flow meters can be taken as net oil flow to the burner. This signal is taken for air/fuel ratio control also. Figure 3.12 shows the oil flow control for recirculating burner provided with steam atomization. Air-fuel ratio control (combustion control) is similar to what has been discussed for gaseous fuel and hence not shown in the figure.

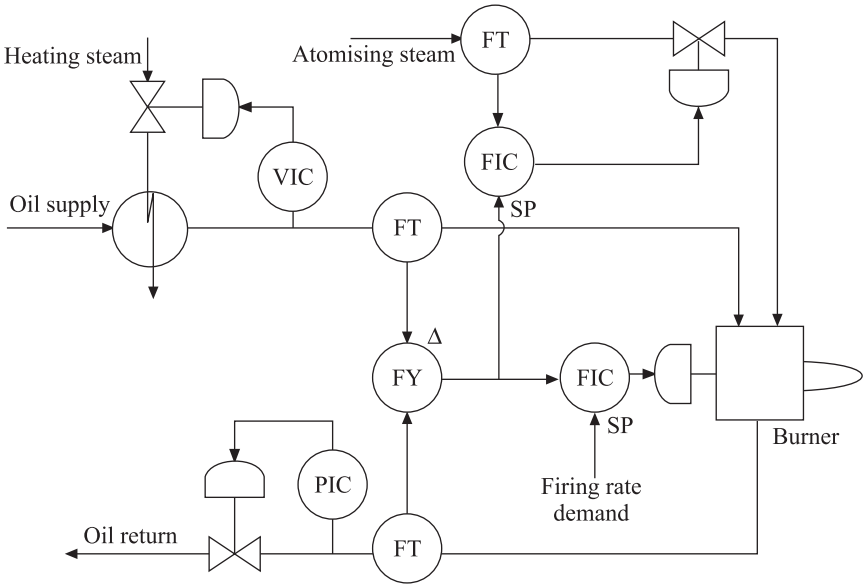


Figure 3.12 Oil flow control for recirculating burner provided with steam atomisation.

The burner back pressure is controlled by the control valve in the recirculating line, whereas the flow controller set point is adjusted by the firing rate demand signal. The firing rate is controlled by an alteration in the opening of the burner orifice. Atomising steam is ratioed to the net oil flow rate, and the heating steam is modulated to keep the fuel oil viscosity constant.

Fuel demand split between oil and gas: In multifuel fired boilers more than one fuel will be used. Figure 3.13 illustrates the controls required when the fuel demand is split between gas and oil on a closed loop basis. The biasing stations provide the means of manual control plus the ability of automatic control, with bias of one fuel with respect to the other.

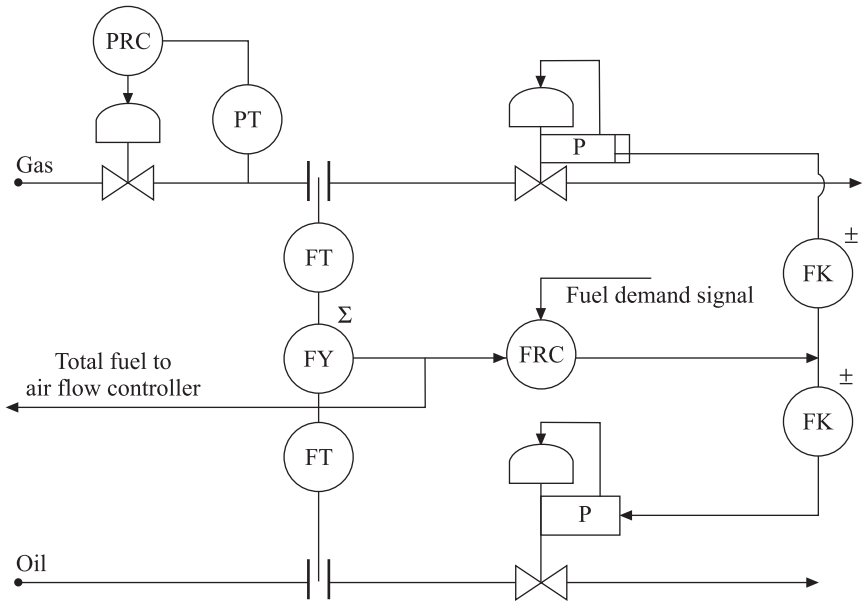


Figure 3.13 Fuel demand split between oil and gas.

If gas fuel is at variable pressure, a pressure control valve is frequently installed upstream to the flow sensor. The total fuel flow to the air flow controller is shown simply assuming that both the fuels require the same ratio of air and the total air is distributed to the burners as required. But in actual practice it is not so. Since one of the requirements ultimately is to have fuels ratioed to combustion air, any totalisation of fuel for control purposes should be on an 'air required for combustion' basis. Hence even if splitting is done as shown in the figure between gas and oil, the combustion controls can be different for gas and oil. Most of the time the ratio of air required to the fuel will be different for gas and oil. Also the design of burners vary between these two fuels. Hence it is always necessary to have independent air/fuel ratio controls for each fuel.

Combustion control with solid fuel

The most commonly used solid fuel is coal. We will restrict our discussions only to coal as solid fuel. Coal is delivered to the user in lump or chunk form by means of trucks or rail wagons. The user must have sufficient space and mechanical equipment for storing and handling the coal prior

to use. The coal is often furnished on a sized basis after preliminary preparation near the mine. The sized coal is transferred from coal storage to coal 'bunkers'. These bunkers or short-term storage bins, are located at an elevation that allows the coal to feed to the boiler system by gravity. There are three basic coal burning methods.

1. On a grate burning
2. Fluidised bed burning
3. In suspension or pulverized coal burning

On a grate burning: For a grate-type burning, coal needs no further preparation and flows by gravity to a stoker hopper. In many cases a weighing system is installed to weigh the amount of coal that is admitted to the stoker hopper. This measurement of coal cannot be used for controlling purposes because of the time lag involved between the measurement and actual firing in the boiler. Hence coal has to be treated here as an 'unmeasured' fuel. In such cases fuel (coal) control systems are open loop, wherein a control signal positions a coal feeding device directly.

A spreader stoker consists of a coal hopper on the boiler front with air jets or rotating paddles that flip the coal into the furnace, where a portion burns in suspension and the rest drops to a grate. Combustion air is admitted under the grate. There is no way to control fuel to a spreader stoker except in an open loop manner by positioning a feeder lever that regulates coal to the paddles.

Combustion air is admitted through fuel bed on the grate from underneath and is adjusted by a single control device. This amount of air is sometimes called 'primary air'. In order to increase the turbulence and complete the combustion, 'secondary combustion air' is added as jets of over fire air above the grate.

Stokers are of three general types having basic subtypes as shown in Table 3.2

Table 3.2 Types of stokers

S. No.	General types	Basic subtypes
1	Spreader stoker	(i) Dump grate
		(ii) Travelling grate
		(iii) Vibrating grate
2	Underfeed stoker	(i) Single-retort
		(ii) Multiple-retort
3	Overfeed stoker	(i) Chain grate
		(ii) Vibrating grate

Combustion control for metering systems: Since a continuous measurement of the fuel burned for use in stoker-fired boiler control systems cannot be obtained, inferential measurement of the fuel input is necessary for 'metering or measured' types of systems. The most common form of inferential relationship that defines combustion conditions is the steam flow/air flow relationship. Steam flow is the usual measurement of heat output. If the combustion air is proportioned to the steam flow (heat output), certain combustion conditions will exist, thus producing a certain boiler efficiency. The steam flow heat output can be divided by the efficiency to produce heat input. Steam flow is thus an inferred measurement of heat input and when correlated to combustion air flow implies a relationship between fuel input and air flow. Series ratio control systems as well as

parallel positioning control systems are adopted with limitations. Alongwith furnace draft control and flue gas analysis trim control, the combustion control can be made meaningful.

Fluidized bed burning: In this process, a bed of material is fluffed into a fluid mass by high velocity air applied from bottom of the bed. An adjustable rate feeder admits the coal to the fluidised bed. For fluidised bed combustion, the fluidised air is the primary combustion air with secondary air added as required to assure complete combustion. Normally the process operates at atmospheric pressure. 'Bubbling bed' and 'circulating bed' are the two types of designs available for atmospheric fluidised-bed boilers.

(a) ***Bubbling bed fluidised-bed boilers:*** Figure 3.14 shows a simplified schematic diagram of a bubbling bed fluidised-bed boiler. The bed is located at the bottom of the furnace where a significant portion of the steam generating tubes is buried in the bed. The fluidizing air, a portion of total combustion air from air preheater, is admitted below a high-density fluidised bed. The bed is fluffed to the bubbling condition by the admitted air. As because the bed is only bubbling, the carryover from the bed to the combustion chamber is low. There will be a large amount of unburned fuel inventory in the bed always. Hence it is better to tackle the load changes by controlling combustion air flow. The bed temperature, which gets affected by the fuel to combustion air ratio and by draining or adding of materials to the bed, can be used for controlling purpose. The key differences from other boilers lie in the control of bed temperature and fuel to combustion air ratio.

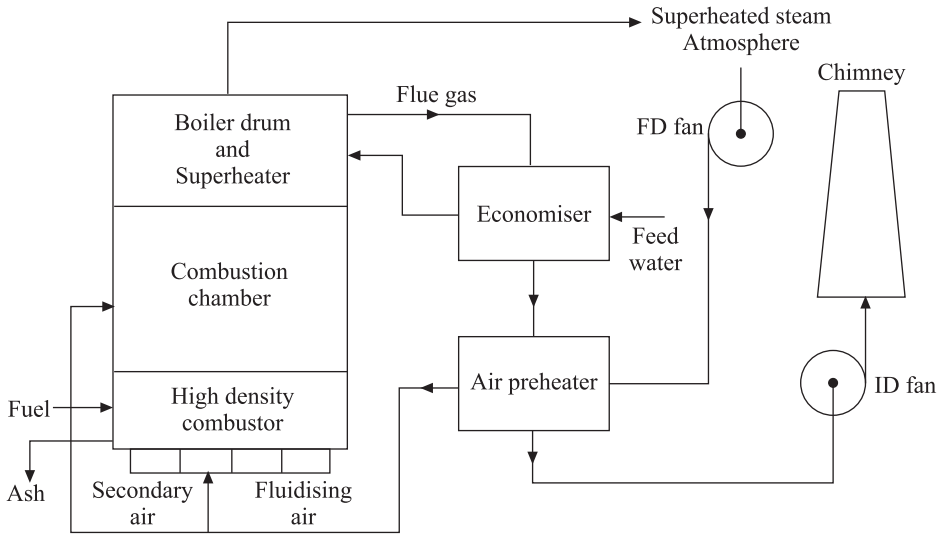


Figure 3.14 Bubbling bed fluidised-bed boiler.

Figure 3.15 shows a combustion control for a fluidised bed boiler with bed temperature trimming. In addition, it is suggested that the flue gas analysis can be used to trim the secondary air flow. The net result is that there will be no change in total air flow, but with a lowered amount of primary or fluidizing air.

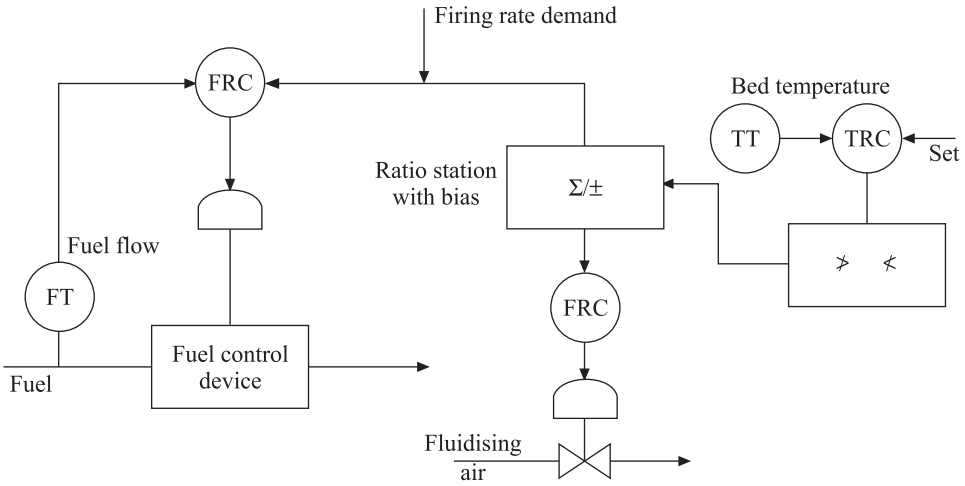


Figure 3.15 Bed temperature trim of air flow control.

(b) ***Circulating bed fluidised-bed boilers:*** The high-density fluidised bed can be made low density one by increasing the velocity of the fluidizing air. The bed volume expands when the velocity of fluidizing air is above that of the bubbling condition. A large amount of bed fuel leave the bed and are carried over to be collected and circulated back into the bed. Figure 3.16 shows a circulating fluidised bed boiler.

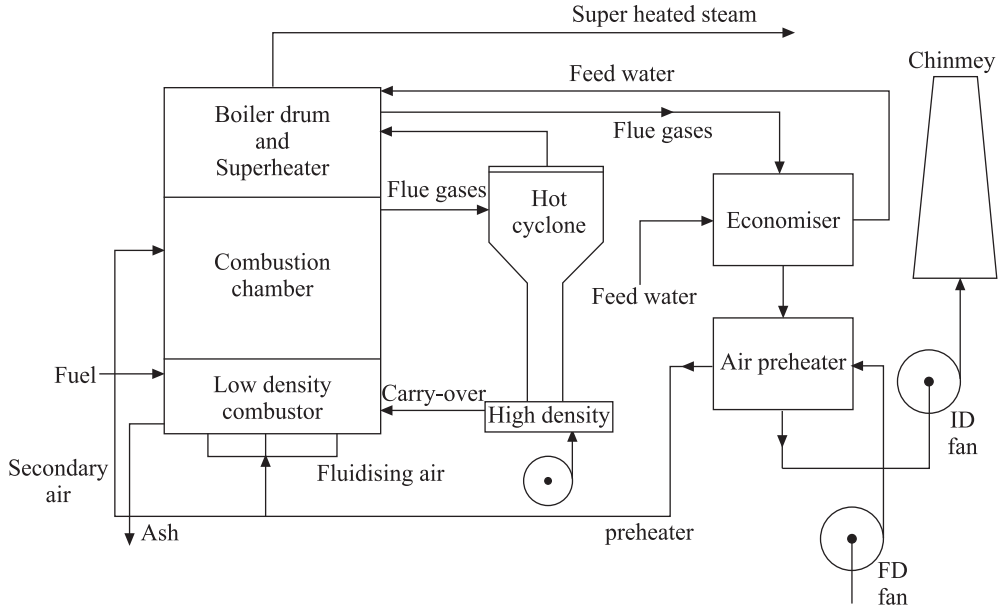


Figure 3.16 Circulating bed fluidised-bed boiler

The primary combustion air enters at the bottom of the combustor as fluidizing air. After partial combustion, the hot gases and burning particles transfer heat to the feed

water to generate saturated steam. Then they enter into a hot cyclone particle separator. The hot gases coming out of the cyclone passes through superheater and economiser afterwards. The controls for circulating bed type boiler are almost similar to that of bubbling bed type boiler.

In suspension or pulverised coal burning: Coal has to be pulverized for burning it in suspension. Coal is ground to a fine powder with the help of coal mill in the pulveriser unit. Different types of coal mills are in operation. There may be two or more pulverisers operating in parallel per boiler. Figure 3.17 demonstrates a direct firing system for pulverized coal. Coal is supplied to the pulverizer from raw coal bunker through adjustable coal feeder. The primary air stream transports the ground fine powder coal to the burner. The temperature of the primary air is controlled so as to ensure that the coal-air mixture is not carrying moisture to the burner.

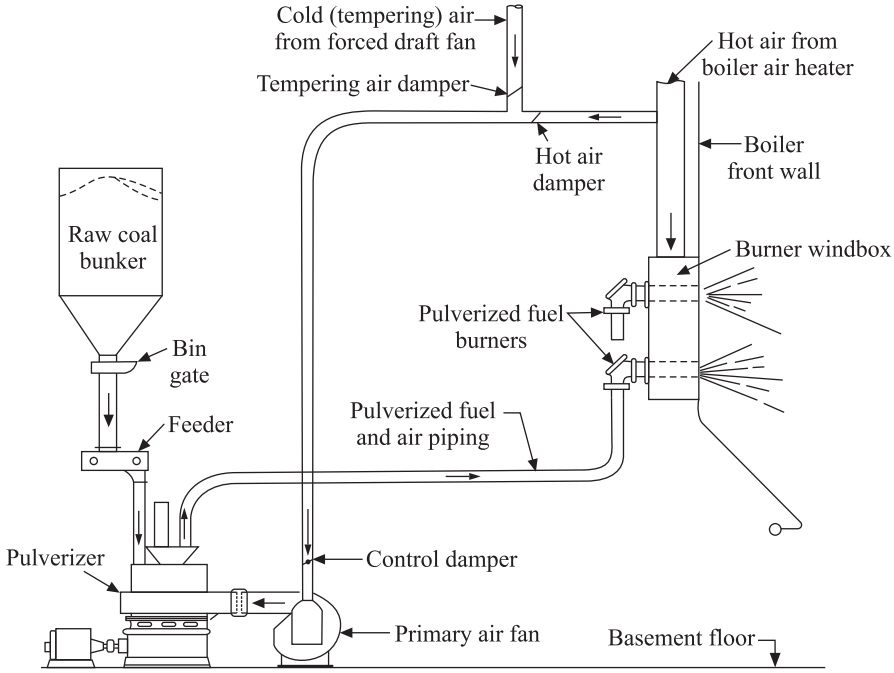


Figure 3.17 Direct-firing system for pulverized coal.

Fuel control: As per the fuel demand, the amount of coal to the boiler is controlled. The coal flow rate control is normally done at the inlet of the mill. Weighment is done by using any of the familiar belt weighers. By measuring the speed of the conveyor and multiplying it with the weight per metre measured by belt weigher, the coal flow rate is calculated. The time delay occurring between the feeding point of coal to the conveyor and that of coal mill plus coal mill delay is taken care of by introducing a lag component in the control system as shown in Figure 3.18.

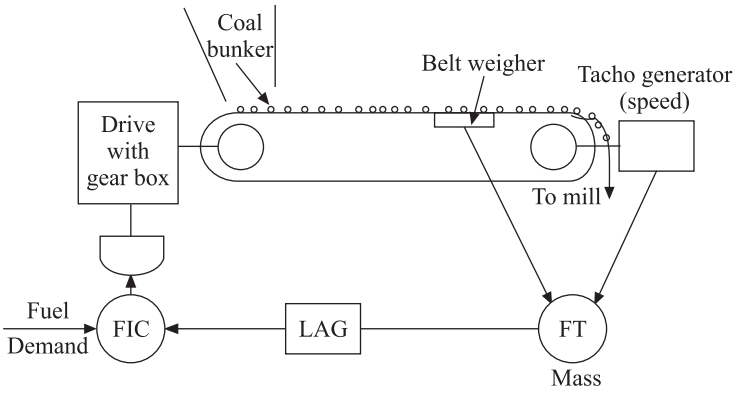


Figure 3.18 Pulverised coal fuel control.

Fuel control with parallel pulverisers: A simplified control schematic in case of two pulverisers operating in parallel is shown in Figure 3.19. The fuel demand is shared as per the bias settings among the pulverisers. The flow of primary air that conveys pulverized coal is manipulated first. The primary air flow becomes set point of coal feed controller of the pulveriser. They act independently with the ratio set between air and coal. The total air flow signal is computed by adding both primary air flow signals and is used for balancing against fuel demand signal. Figure 3.18 may be referred to for better understanding of coal feeder control as only simplied control schematic is shown in Figure 3.19.

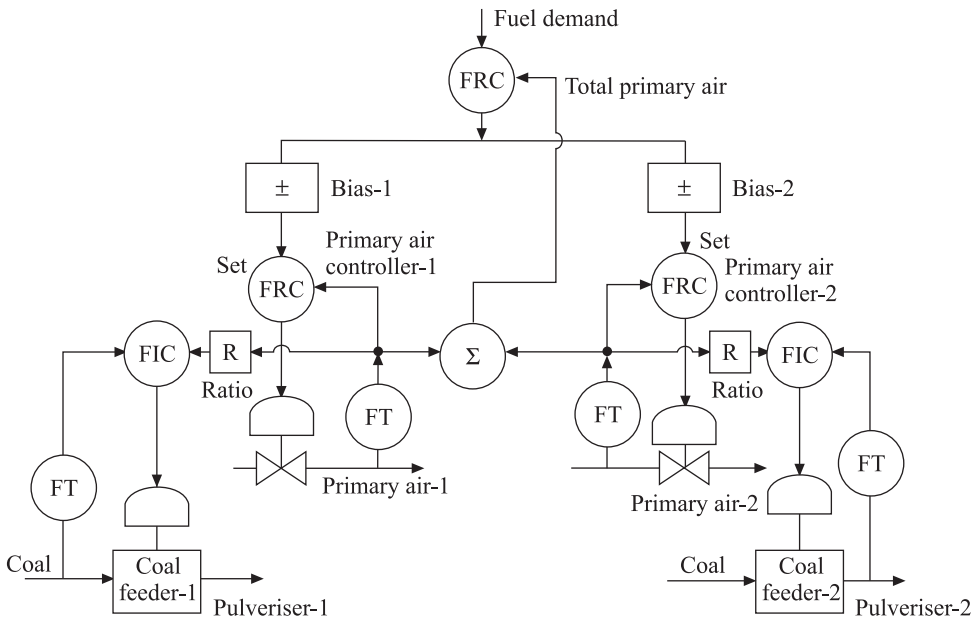


Figure 3.19 Fuel control with parallel pulverisers.

Primary air temperature control: Primary air temperature control is necessary as the fuel flows in the current of primary air and hence to maintain a maximum safe operating temperature in the pulveriser. A simple feedback control arrangement is shown in Figure 3.20 where cold and hot combustion air is mixed ahead of the primary air fan to control the temperature of the coal-air mixture in the pulveriser.

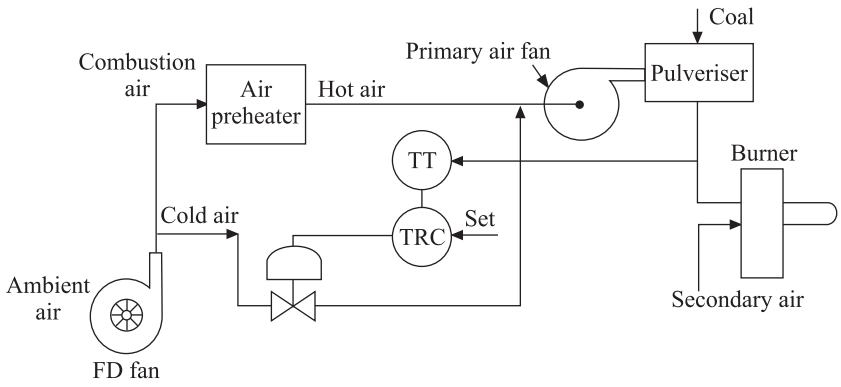


Figure 3.20 Primary air temperature control.

Combustion control: Combustion control system for pulverized coal firing will be similar to that of gaseous fuel. The primary air which carries pulverized coal plus secondary air, the main component of combustion air, added at the burner to form the total combustion air. Figure 3.21 shows a simplified coal-air ratio control where the fuel demand signal simultaneously controls both fuel and air supply to have faster response compared to that of controls shown in Figure 3.19 where air leads fuel.

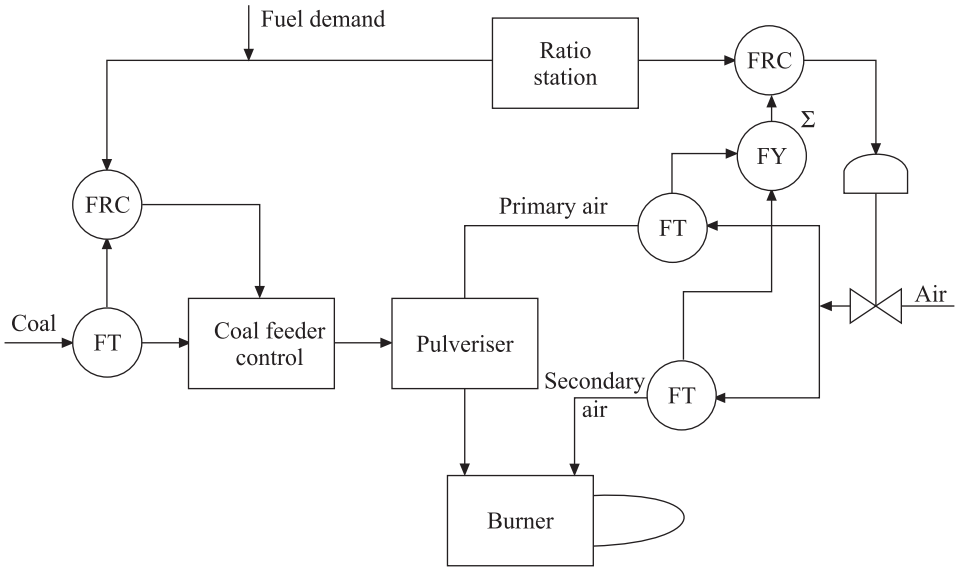


Figure 3.21 Coal-air ratio control.

Trimming (or optimisation) of combustion control systems

Optimisation of combustion control is aimed at improved efficiency and economy of operation of a power plant. It may require some additional instruments, analysers and controllers. Even minor improvements in efficiency of operation will compensate for the expenditure made for those additional units. In power plant operation, the optimisation of combustion control use two main techniques. They are:

1. Excess air optimisation (Minimisation of excess air)
2. Stack temperature optimisation (Minimisation of stack gas temperature)

Excess air optimisation (Minimisation of excess air): The contribution of combustion air to the furnace losses is well known. If combustion air supply is in deficient, proper combustion of fuel may not take place and hence loss due to unburned fuel will be more. If combustion air supply is more than what is required, the loss due to unburned fuel will be negligible, whereas the heat loss due to heat energy carried away by flue gas will increase. Before adopting optimisation techniques one should be clear about the furnace losses and the causes for that. Assuming one particular fuel is used for combustion, the furnace losses are mainly divided into three parts.

1. Loss due to unburned fuel or incomplete combustion loss
2. Loss due to heat energy carried away by flue gases or flue gas loss
3. Loss due to radiation and wall losses

1. ***Incomplete combustion loss:*** When air deficiency is there, the fuel atoms do not find enough oxygen atoms to get burned. Then some combustibles are left unburned. This unburned fuel quantity gets reduced when enough or excess combustion air is supplied. The loss due to incomplete combustion will be almost negligible in the excess air region.
2. ***Flue gas loss:*** The heat losses occurring due to the heat energy carried away by flue gases is called *flue gas loss*. After combustion the hot flue gases transfer heat energy to feed water in the boiler tubes, to saturated steam in the superheater, to cold feedwater in the economiser and to cold combustion air in the air preheater. After transferring heat in the air preheater, flue gases are let into atmosphere through ID fan and chimney. They are sometimes called *waste gases* because no more heat energy is extracted from flue gases after air preheater unit. Under air-deficient conditions unburned fuel carries heat energy along with flue gases, and in air excess conditions the heat loss is due to unused oxygen and the accompanying nitrogen carrying away heat energy when discharged into atmosphere. There is always a trend of steady increase in flue gas loss as the air consumption goes up.
3. ***Radiation and wall losses:*** These losses depend mainly on the combustion chamber temperature and the refractory wall conditions. Radiation and wall losses are relatively constant throughout the operating region except when the excess air allowed is much more than required. In that case the combustion chamber will have a tendency to cool down and hence the reduction in losses (Figure 3.22).

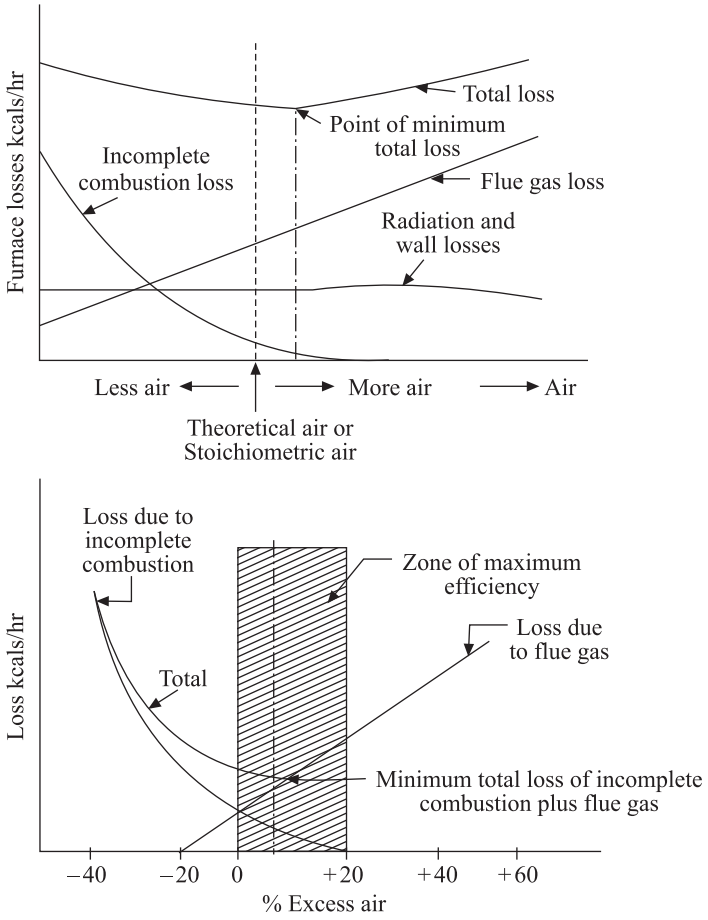


Figure 3.22 Furnace losses versus excess air.

If we plot various furnace losses and total loss as a function of excess air, it will resemble like the one shown in Figure 3.22. Most efficient operation of a boiler is considered to be at the minimum total loss point. The purpose of optimum control system is to determine the minimum loss point at the operating load and adjust the excess air accordingly. As no burner is capable of cent percent effective mixing, the minimum loss point is always in the excess air region. Due to excess air, each carbon molecule is converted into carbon dioxide, whereas not all oxygen molecules would find corresponding carbon molecules. That is why the theoretical minimum loss point is different from actual one. At this actual minimum loss point the flue gas losses balance the incomplete combustion losses. Flue gas analysers are installed to know the percentage of O_2, CO_2 and CO present in flue gas and the information can be effectively used for optimization purpose.

Stack temperature optimization (Minimising stack gas temperature): The stack temperature has to be minimised to keep the total losses at a minimum point. The trend of fuel-saving potential against stack temperature and percentage excess oxygen in flue gas is shown in Figure 3.23. By optimisation techniques the temperature of the stack can be brought down to minimum level so as to achieve maximum fuel saving. Using oxygen analyser in flue gas for combustion trimming

further fuel saving is possible by reducing the percentage oxygen in flue gas for the minimum stack temperature. The best operating point for the boiler under analysis with a particular design using a particular fuel is at 200ºC stack temperature and 2% oxygen in the flue gas.

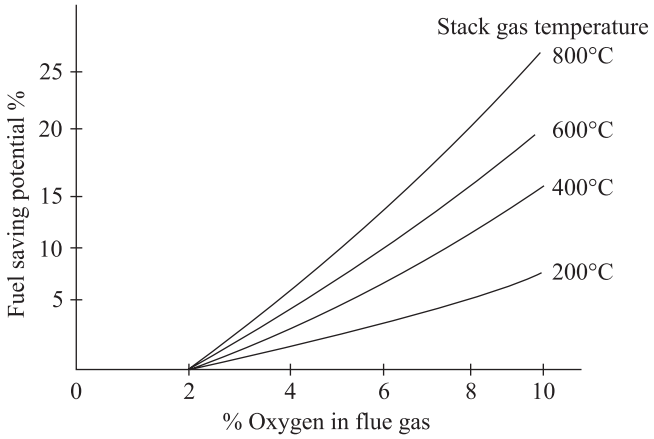


Figure 3.23 Fuel-saving potential versus stack gas temperature and % O_2 in flue gas.

Optimisation using stack gas analysers: From Figure 3.24 one can see the normal trend of stack gas components like fuel, CO, CO_2 and O_2. Assuming the fuel as coal, the combustion control is done so that enough air is provided to convert the whole carbon into carbon dioxide. The percentage of excess air varies with so many factors like boiler load, ambient conditions, boiler design, fuel used etc. The information regarding fuel and CO_2 in the stack gas will not be of much use for the optimisation purposes. The measurements of CO and O_2 in stack gas can be effectively used. CO present in the stack gas can be utilized for optimising boiler efficiency under variable fuel, load and ambient conditions.

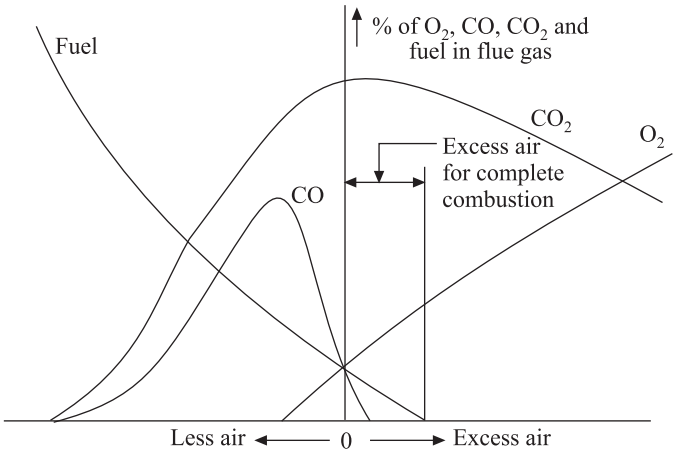


Figure 3.24 Combustion air versus stack gas components.

(a) ***Air-fuel ratio control with O_2% trimming:*** In this control O_2% trimming is introduced in a normal control circuit used for combustion control. Figure 3.25 shows one such superimposed control facilitating O_2% trimming. The basic combustion control is the same as the one discussed with reference to Figure 3.9 (metered parallel air-fuel ratio control). The added functional unit $FY^{f(x)}$ is loaded with the boiler steam load versus percentage oxygen in the stack gas relationship for optimum operation. Depending on the steam load % O_2 set point is generated for the oxygen trim controller ARC. Comparing this set value with actual % O_2 signal from the analyser AT, the controller generates trimming signal which can be added or subtracted from the set value applied to the existing air/fuel ratio control.

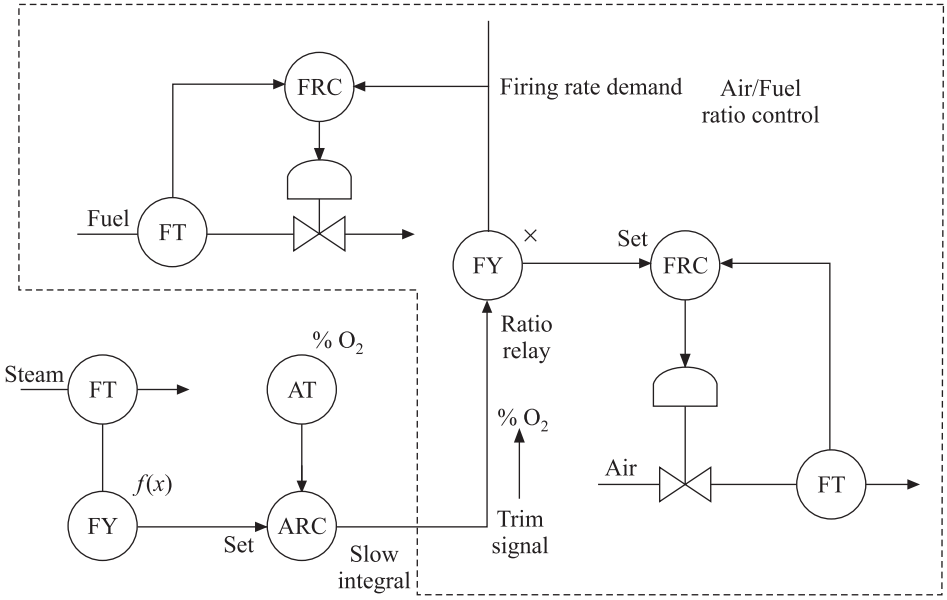


Figure 3.25 Air-fuel control with % O_2 in flue gas trimming.

(b) ***Air-fuel ratio control based on CO also:*** A control system with % O_2, CO and steam flow for trimming is shown in Figure 3.26. This control system utilizing the measurement of both % O_2 and % CO can optimize boiler efficiency even if load, ambient conditions, or fuel characteristics vary. The final trimming signal (controller output given to Air-fuel-ratio control) is always clamped by high and low limits (not shown in the figure) to prevent driving the air/fuel ratio beyond unsafe or inefficient limits.

3.3.2 Furnace Draft Control

A basic boiler has a steam-water system and a fuel-air-flue gas system. In the fuel-air-flue gas system, the air and fuel are mixed and ignited in the furnace (combustion chamber). Air and fuel flow into the furnace and flue gas flows out. The force driving this flow is the differential pressure between the gases inside the furnace and those outside the furnace. Furnace pressure is commonly referred to as draft or draft pressure.

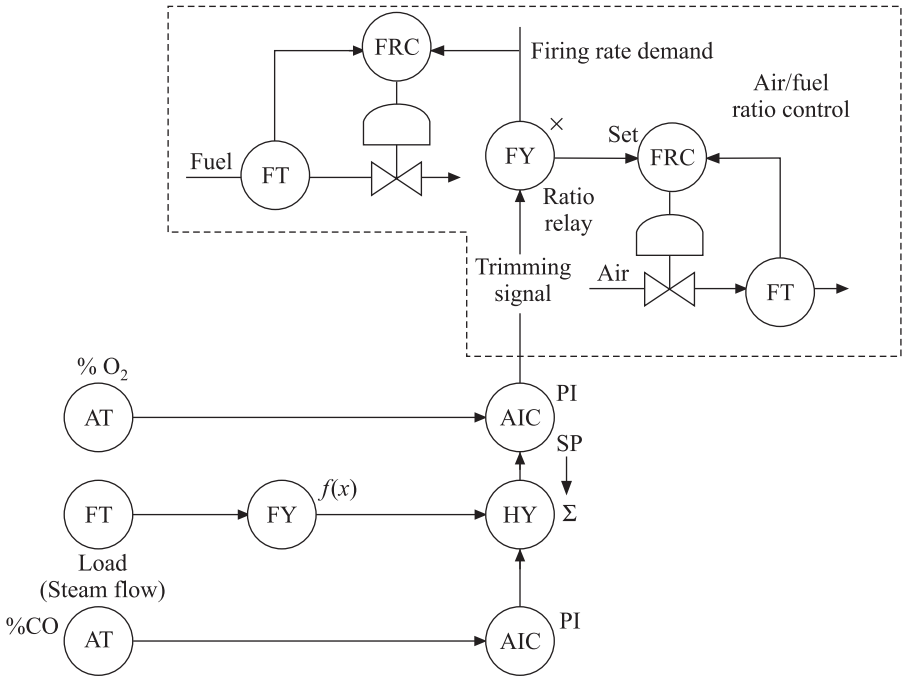


Figure 3.26 Fine trimming based on % CO.

In addition to fuel, combustion requires oxygen and therefore air. To move this air through the fuel bed and to produce a flow of the gaseous products of combustion out of the furnace, then through superheater, economiser, air preheater etc. requires a difference of pressure equal to that of necessary to accelerate the gases to their final velocity plus friction losses. This difference of pressure is called *draft* whether measured above or below atmospheric pressure. This draft is normally maintained slightly negative to prevent the combustion products and ash from being discharged from the furnace into surrounding areas through inspection ports, doors, feeders etc. Also this should be as close to atmosphere as possible, thereby minimizing the ingestion of excess air drawn through openings.

Normally in a boiler, forced draft (FD) fan draws air from atmosphere and gives big boost to the draft. In addition liquid fuel and gaseous fuels also add pressure in the combustion chamber. After the combustion, the flue gases, travel towards chimney to be let out in the atmosphere through economiser, air preheater etc. which are normally pressure reducing components. Finally, when chimney is not in a position to develop enough natural draft to push the complete flue gas, the induced draft (ID) fan comes into picture to serve the purpose. Fans and chimney produce pressure in the positive direction; friction, turbulence, fuel bed resistance and the like consume draft and produce decreasingly positive or increasingly negative pressure.

Furnaces are classified by the method for moving air and other gases through the system.

Natural draft

A natural draft furnace uses the stack (chimney) effect. Gases inside the stack are less dense than those outside the chimney. The gases in the stack will rise, creating a vacuum (suction) which will

draw the combustion gases or flue gas out of furnace. Natural draft furnace naturally operate below atmospheric pressure. The draft that will be produced by a stack is a function of the height of the stack and the flue gas temperature. Natural draft is normally used to supplement rather than to substitute mechanical draft produced by fans.

Forced draft

A forced draft furnace uses a fan or blower to force combustion air through the system by sucking air from the atmosphere. Control is accomplished by regulating the fan speed or damper operation. This type of furnace is operated slightly above atmospheric pressure.

Induced draft

A fan at the end of the boiler flow system path that takes its suction from the boiler flue gas stream and discharges the flue gas to the stack is called an *induced draft fan*. It draws gases through the furnace and the combustion air into the furnace. An induced draft fan makes high stacks unnecessary. Control is accomplished by regulating the fan speed or damper operation. An induced draft furnace is operated slightly below atmospheric pressure.

Balanced draft

Furnaces equipped with both FD and ID fans are called *balanced draft* systems. To control furnace pressure, it is necessary to maintain a balance between the flow in and flow out of the furnace. Balanced draft furnaces operate at slightly negative pressures to prevent flue gas leakage to the surroundings. However too low a pressure must also be avoided to minimize air leakage into the furnace and, in the extreme, to prevent furnace implosion. FD fan damper is generally manipulated by the air flow controller, and the ID fan damper is manipulated by the furnace pressure controller.

F.D. fan control (forced draft control): In a thermal power station with a number of boilers in operation, a master controller decides the load sharing among boilers and hence the fuel rate. Depending on the fuel rate to a particular boiler, the air requirement and hence the draft to be developed by FD fan is decided. FD fan controls are done boiler-wise. Forced draft fan along with its inlet vane control arrangement is engaged for the control of combustion air. It is done taking either the furnace inlet air pressure or total air flow into consideration. Air flow signal keeping the air pressure constant or air pressure signal is an input to the controller. The controller output controls the inlet vanes of the FD fan to achieve the result. Instead of inlet vane/damper control, the fan speed control is also possible, but it is very expensive. A simplified schematic diagram with vane control is shown in Figure 3.27.

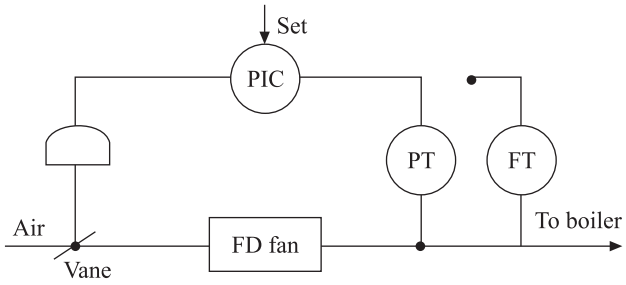


Figure 3.27 Combustion air draft control.

This type of control takes care of total air requirement to the boiler as demanded by the master controller. The draft thus generated is called *forced draft* which takes care of losses in air duct and preheater, and fuel bed resistances.

Furnace pressure (induced draft) control: The purpose of this control is to keep the furnace/combustion chamber pressure at a slightly negative value. This is achieved by induced draft fan with damper control. The range of pressure transmitter used here may be around ±20 mmWg. The measurement of furnace draft produces noisy signal, limiting the loop gain to relatively low values. In some cases it may be necessary to use only integral control to stabilize the loop. Additionally, stability and interaction problems may occur in the overall systems because of measurement lags. Figure 3.28 shows a simple schematic diagram of a furnace draft or induced draft control.

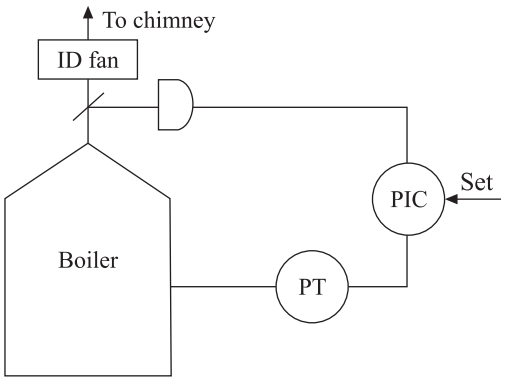


Figure 3.28 Furnace pressure control.

Balanced draft control: In large boilers, balanced draft control is employed. Both FD fan and ID fan are put into operation together. As FD fan creates positive pressure in the beginning of the flow path and ID fan creates suction pressure almost at the end of the path, at some point in the path the pressure will be same as that of atmosphere. It is designed in such a way that the combustion chamber pressure is slightly negative so that there is neither hot gas leakage nor excessive cold air infiltration. It is achieved by keeping the pressure at the top of the furnace slight negative.

In balanced draft system FD fan loop is used to satisfy the total air flow requirement and ID fan loop is used for controlling furnace draft. There is always a possibility of interaction between these two loops. Suitable designs are to be made to minimize interaction between them. One such system is shown in Figure 3.29 where both FD and ID dampers are operated parallel. Air flow controller moves FD fan damper directly and ID fan damper with a time lag. Air flow controller signal to furnace draft controller is considered to be feed forward signal. Hence whenever the air flow to the furnace is changed, the outflow from the furnace will also start changing, of course with a dynamic compensation lag. The mismatch is finally corrected by the furnace pressure controller though it will need only to trim the feed forward signal at PY.

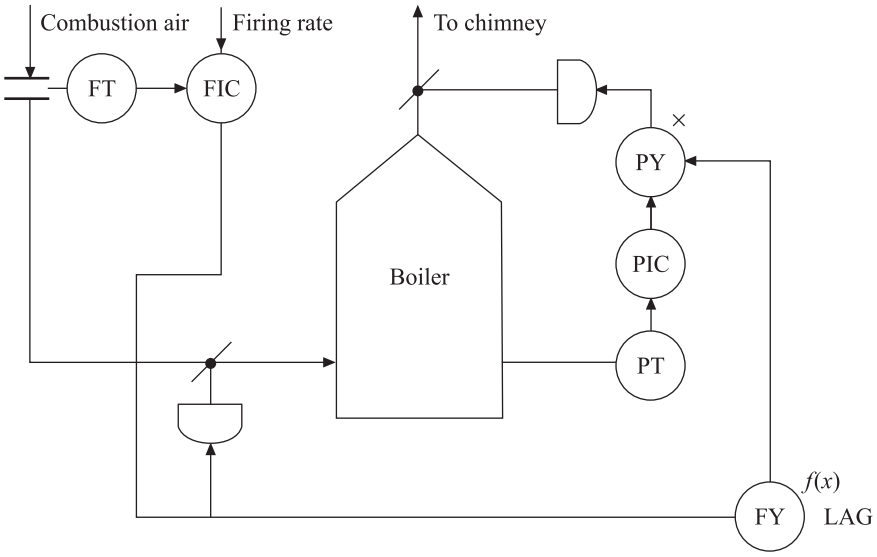


Figure 3.29 Balanced draft control.

3.4 ANALYTICAL MEASUREMENT

In this section flue gas analysers for O_2%, CO_2% and ($CO + H_2$)% (combustibles) will be discussed in addition to smoke density measurement and dust monitor. Limited discussions on fuel analysers, pollution monitoring instruments and chromatography will be done.

3.4.1 Oxygen Measurement in Flue Gas

The thermal efficiency of the boiler is controlled with the knowledge of oxygen percentage in flue gas. This information is helpful to set proper air/fuel ratio and obtain optimum excess air. The Orsat apparatus which works on selective chemical absorption principle is considered primary standard for volumetric analysis of products of combustion. This can be used only for sample analysis but not as continuous online instrument. Online oxygen analysers are available using the following two principles.

1. Using paramagnetic property of oxygen.
2. Using zirconium oxide probes.

Paramagnetic oxygen analyser

Among industrial gases which are of interest to us, only oxygen is highly paramagnetic. This property decreases as the temperature increases. The poles of a permanent magnet extend into a test cell made of a non-magnetic material. A platinum resistance wire which can be electrically heated to about 300ºC is mounted in the zone of maximum field strength. A circulation of the flue gas is produced due to thermal updrift. The magnet at first exert a strong attraction upon the oxygen present. As the latter is heated, it loses part of its paramagnetism and is replaced by colder and more active oxygen. The resultant gas circulation cools the platinum wire and causes unbalance

voltage in the bridge which is a measure of oxygen percentage in the flue gas. Figure 3.30 shows the basic Wheatstone bridge arrangement used for measuring oxygen percentage in flue gas using paramagnetic principle. Figure 3.31 shows how oxygen is influenced by the magnetic field and is forced to flow through the heated platinum wire placed in the magnetic field. To double the sensitivity of the bridge, two arms of the bridge are exposed to magnetic field. The other two arms have dummy pole shoes to give a reference for the effect of the thermal updrift while retaining geometric symmetry. Figure 3.32 shows the complete equipment with sampling system and suction pump.

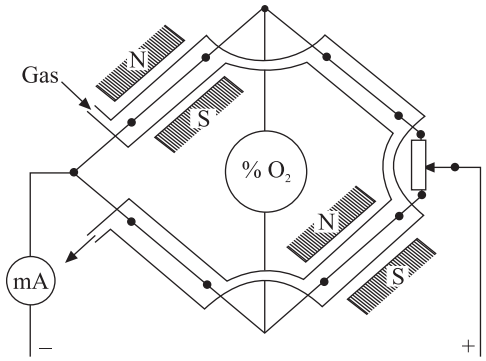


Figure 3.30 Basic circuit of oxygen analyzer.

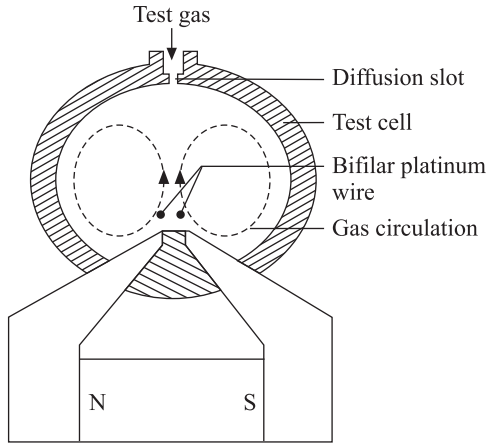


Figure 3.31 Schematic diagram of oxygen test cell.

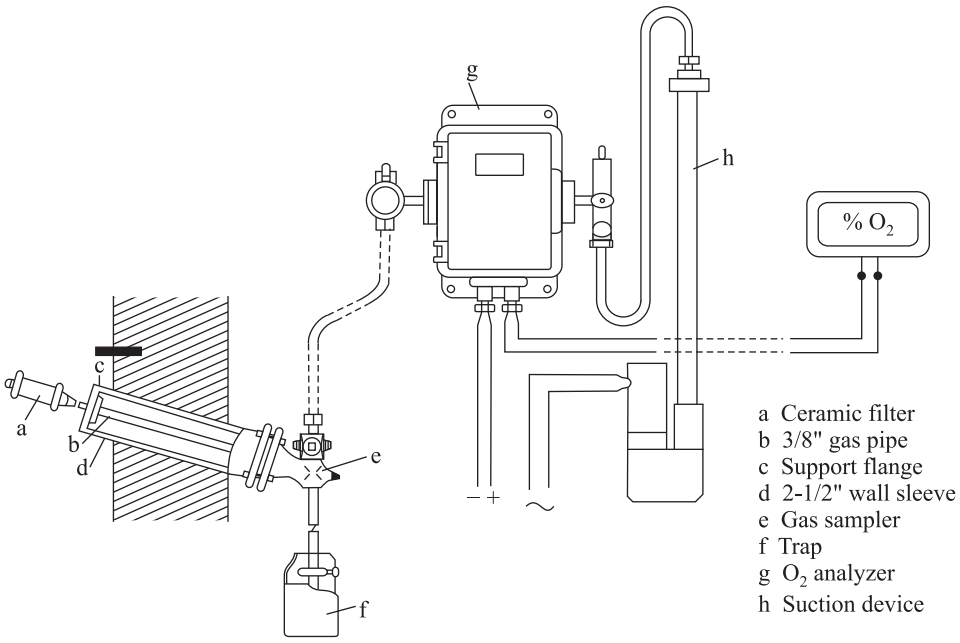


Figure 3.32 Complete equipment of oxygen analyzer.

Oxygen analyser using Zirconium oxygen probe: The flue gas analysis for percentage oxygen using paramagnetic analyser discussed above is carried out by extracting a sample, filtering, cooling and drying it before passing it to the analyser proper. Frequent maintenance is necessary to prevent sampling system blockage. Specialized skills are required to keep it in operation and for calibration. Solid state zirconia sensor is designed around rugged non-sampling techniques to withstand the flue gas environment which is known as in-situ sampling.

The ceramic material zirconium oxide (ZrO_2) when heated, acts as a permeable membrane to oxygen. In other words, the zirconium oxide ceramic sensing element is a closed-end tube which when hot $(\simeq 700°C)$ conducts oxygen ions. Porous platinum coating on the inside and outside of the tube serve as electrodes. When the two electrodes are in contact with gases having different levels of partial pressure, a voltage is produced depending on the ratio of partial pressure satisfying the following equation.

$$E = \frac{RT}{4F} \log \frac{P_1}{P_2} + C$$

where

E = Output voltage from the cell
R = Gas constant
P_1 = Partial pressure (concentration) of oxygen in one side [Reference gas side. Normally air is used]
P_2 = Partial pressure (concentration) of oxygen in flue gas.
C = Cell constant
T = Absolute temperature of the cell
F = Faraday's constant.

Figure 3.33 shows a zirconia element equipped with platinum electrodes, thermostatic heating and a source of air as reference gas. The other side of the probe is exposed to the flue gas. The oxygen partial pressure on the reference side of the cell is known and hence the emf produced by the cell indicates the oxygen content of the flue gas.

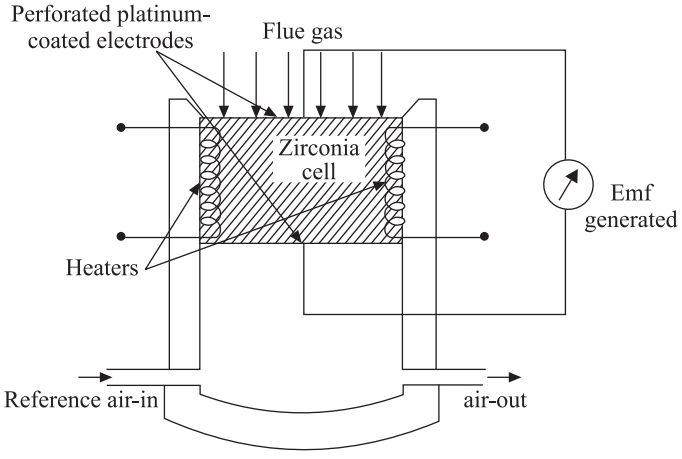


Figure 3.33 Zirconium oxide probe.

The most common form of the zirconia analyser comprises a probe-mounted zirconia element inserted into the flue duct. In some cases a porous filter is used to protect the element. The probe tip is heated to high temperatures ($\cong 700°C$) by heaters. The electrical signal from the probe is taken to a meter or to an electronic unit where O_2 concentration is calculated and read. Calibration facility and self-diagnostics are incorporated in microprocessor-based electronic units.

The analyser does not have any gas sampling portion and hence needs little or no maintenance. It responds quickly and provides stable measuring for longer periods of time.

3.4.2 Measurement of Carbon Dioxide in Flue Gas

The complete combustion of the fuel and the analysis of flue gas to find it out is very important thing in thermal power stations. Complete combustion is the term used to designate a total conversion of the carbon present into carbon dioxide (CO_2), hydrogen into H_2O and sulphur into SO_2. The measurement of CO_2 in flue gas gives an idea of how effectively the combustion has taken place in the boiler. Though there is no absolute value of CO_2 to represent complete combustion, the variation of CO_2 with time and fuel consumed will have an indication.

Thermal conductivity principle is normally employed for measuring CO_2. Thermal conductivity of CO_2 is quite low compared to other principal constituents of flue gases namely N_2, O_2, H_2 and CO (Refer to Figure 3.34).

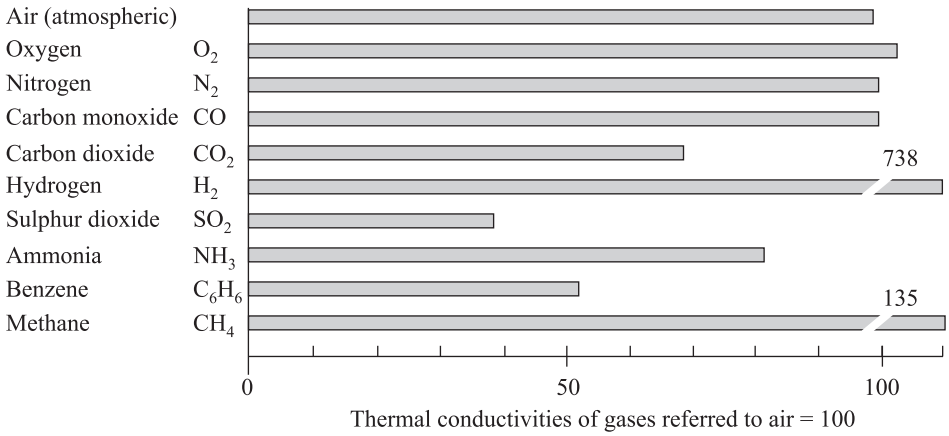


Figure 3.34 Thermal conductivities of various gases at 100ºC.

To determine the CO_2 content the flue gas is passed through two test cells and air through two reference cells in which they flow around stretched platinum resistance wire which are heated electrically to about 100ºC (Refer to Figure 3.35). Test gas and reference air transfer the generated heat to the cell-walls in accordance with their individual conductivities. The conductivity of the flue gases decreases as their CO_2 content increases; at the same time the temperature and hence the resistivity of the heated wires increases. The unbalance thus caused in the bridge is measured and instruments calibrated in percent carbon dioxide by volume. For instance, 20% by volume of CO_2 in a flue gas will increase the temperature of the heated wires by approximately 6ºC and thereby increase the electrical resistance by 0.2 ohms.

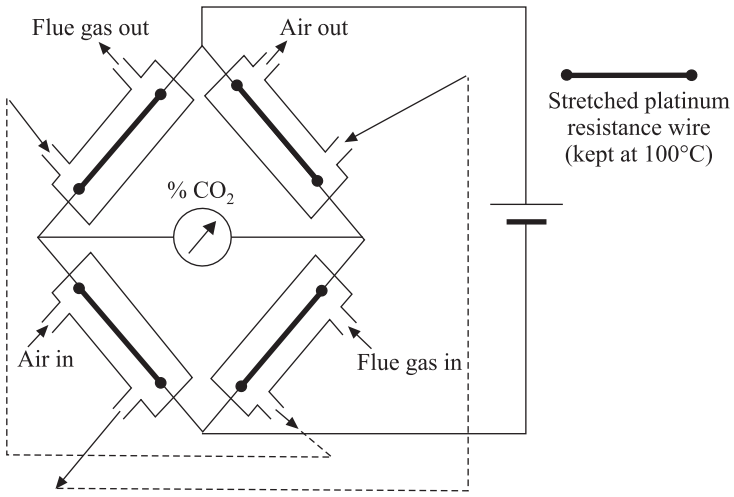


Figure 3.35 CO_2 analyser-thermal conductivity method.

3.4.3 Combustibles Analyser (CO + H_2)

The indication of incomplete combustion can be had by detection of combustibles (CO and H_2) present in the flue gas. By detecting the amount of carbon monoxide (CO) and hydrogen (H_2) present in the flue gas, one can determine combustion efficiency.

The CO measurement which also includes the determination of any hydrogen present is based on a 'thermal effect' called *heat of combustion* method. Platinum-iridium wires stretched in a test and reference cell are heated electrically to 500ºC. The test gas (flue gas with air added) flows around the wire in the test cell, while the other cell is filled with reference air (Refer to Figure 3.36). The CO + H_2 mixture is burned catalytically in the presence of the platinum iridium wires. This causes a considerable increase in the temperature of the wire in the test cell and hence in its resistivity.

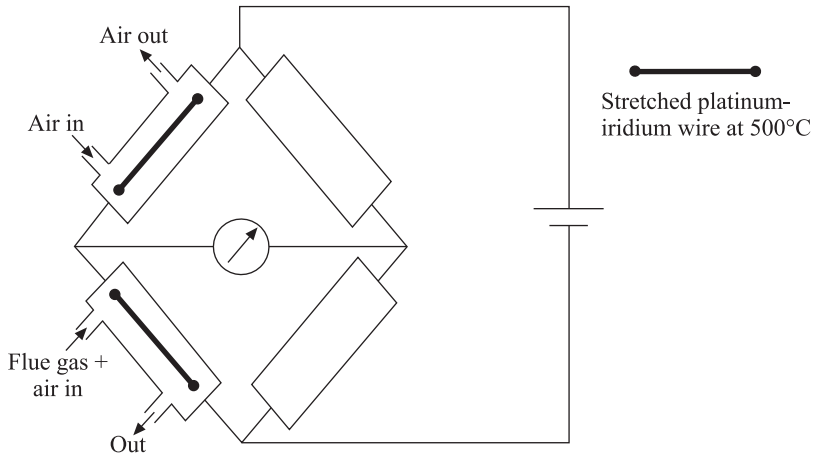


Figure 3.36 Combustibles analyser–heat of combustion method.

3.4.4 Infrared Flue Gas Analysers

A portion of the infrared spectrum will be absorbed when infrared light passes through certain gases. Carbon monoxide, carbon dioxide and many other gases have infrared absorption characteristics. Elemental diatomic gases like oxygen, hydrogen, nitrogen, etc. do not exhibit such characteristics. The concentration of any component which exhibits infrared absorption characteristics in a mixture can be determined by its unique absorption pattern.

The infrared analyser using infrared technique is shown in Figure 3.37. Two similar infrared sources—may be with Nichrome filaments–are used as infrared radiation sources. Beams from sources travel through the sample cell and comparison cell respectively. Between the source and the cells a chopper mechanism is operated so that it blocks the radiation to the sample cell and comparison cell alternatively. The emergent radiation from both the cells enter opposite ends of a detector cell. The detector chamber is divided into two compartments by a metallic diaphragm and filled with the gas to be measured to the same pressure. The metallic diaphragm along with a fixed electrode forms a condenser to be connected to an amplifier for further processing.

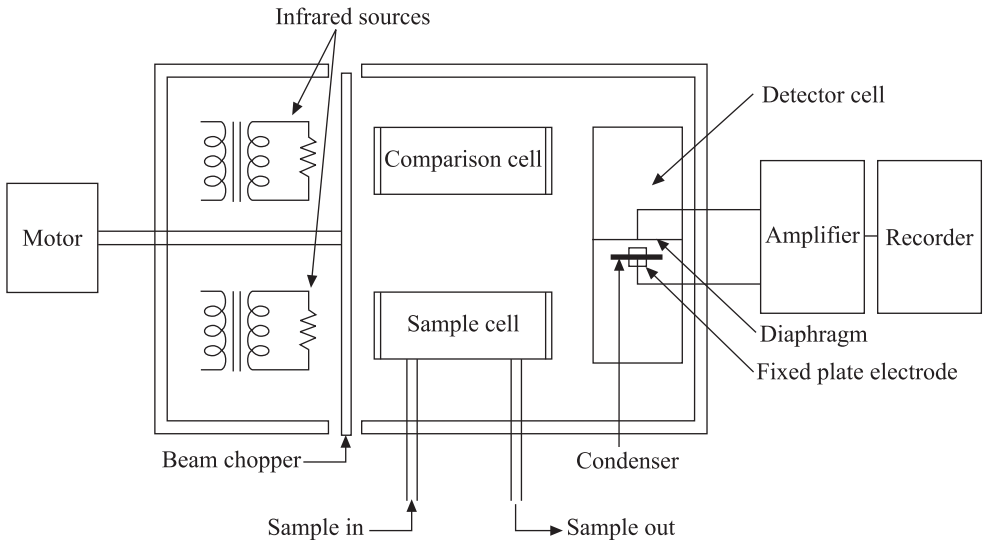


Figure 3.37 Infrared gas analyser.

Working of the infrared analyser

Comparison cell is filled with any of the diatomic gases like O_2, N_2 or H_2 which do not absorb infrared energy. The sample cell is also filled with the same diatomic gas as in comparison cell for adjusting the zero of the analyser. Then the sample is passed through the sample cell. Now the amount of infrared energy absorbed will depend upon the components present in the sample. Let us assume that we are interested in measuring CO_2 component. In that case the detector cell is filled with CO_2 gas on both sides. When the unit is under operation, the energy received from the sample side in the detector will be less by an amount equivalent to CO_2 component present in the sample compared to the energy received from comparison cell. The difference in energy levels

received and finally, absorbed by CO_2 present in both sides of the detector cell will cause temperature and hence pressure difference. As the chopper allows the entry only alternatively, the metal diaphragm vibrates at the chopping frequency (normally varies from 2 Hz to 10 Hz) with the magnitude of displacement from fixed electrode equivalent to CO_2 content with sample. The resultant capacitance of the condenser is the measure of CO_2 in our case. The condenser capacitance is measured using amplifier and calibrated for indicating and recording. If the same analyser is to be used for measuring CO, the detector cell will be filled with CO and the calibration done accordingly (Figure 3.37).

An improved version with single infrared source is shown in Figure 3.38. The minor difference caused due to non-similarity of sources can be eliminated here. Infrared analysers can be used to analyse independently the CO, CO_2, NO_X, SO_X etc. present in flue gas of a thermal power plant.

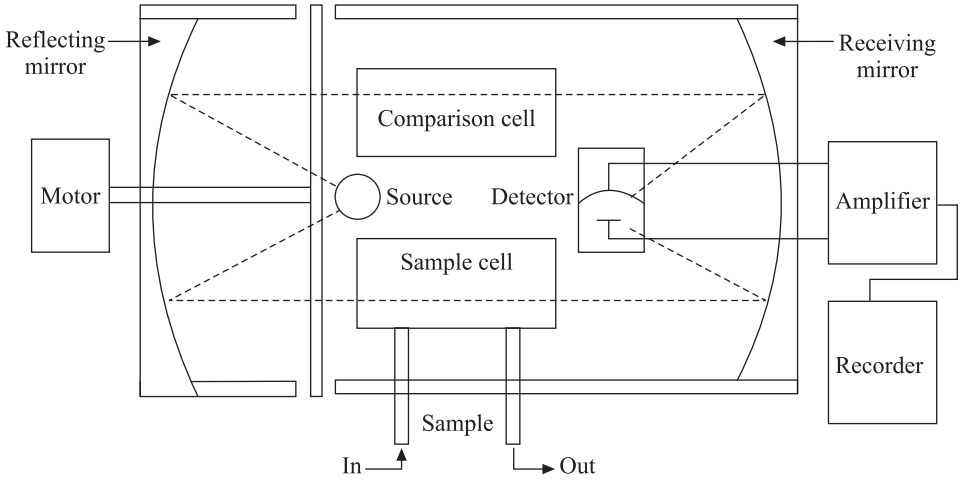


Figure 3.38 Infrared gas analyser with single source.

3.4.5 Smoke Detector

In earlier years, smoking through chimney was considered as the scale to measure the industrial development of a country. More number of chimneys emitting different colours of smokes were belonging to advanced nations. The environmental awareness nowadays has forced one to think that the discharging of smoke into the environment is an unnecessary evil. Effect on health of human beings, falling standard of living of people in the vicinity of smoke emitting chimneys and the financial loss due to incomplete combustion, forced one to think about measuring smoke density and taking preventive measures to improve upon in those three counts. Colour of the smoke from white to black also gives some idea about the smoke density and the incomplete combustion rate. The levels of emissions of different constituents imposed by government regulatory authorities like pollution control board have to be followed to avoid penalties and legal proceedings.

Photocell type smoke detectors are used most commonly in the thermal power plants. The projector with light source to focus light beam through the duct or chimney is installed on one side of the chimney. The receiver with photocell to receive the light energy focused from the projector is fixed exactly on the opposite side. Both projector and receiver are supplied with controlled power. The control unit consisting of indicator, recorder and annunciation system is added.

The variation of the obscuration of the light source due to smoke and dust in the flue gas generates a signal in the photocell circuit. The variation in the signal which is a measure of dust and smoke in the flue gas is processed further by the electronic circuit and displayed in the control unit. The final indication or recording is calibrated in percentage obscuration. A simplified sketch of a smoke detector using 'obscuration' principle is shown in Figure 3.39. Regular cleaning of projector and receiver lenses and provision of extension tubes are found useful to minimize the fouling.

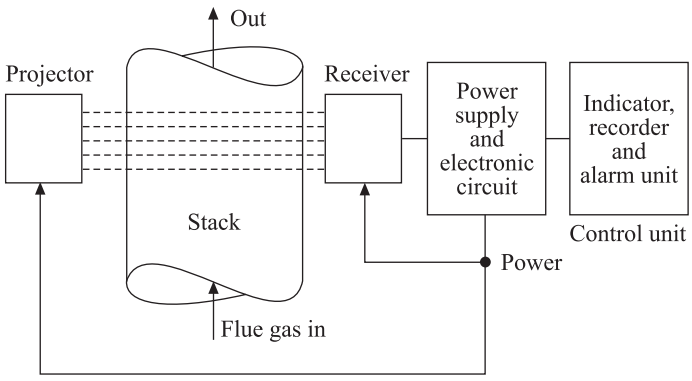


Figure 3.39 Smoke detector using 'obscuration' principle.

3.4.6 Dust Monitor

The majority of the thermal power plant boilers use coal as main fuel. When coal is burned in suspension, there is always a possibility of coal-dust and fly-ash being carried away along with flue gas. It is essential to measure the amount of dust particles coming out of chimney and getting into atmosphere. It is also important to comply with the norms of the government regulatory bodies.

Optical type, electrical type, electrostatic type and reflected light type are the commercially available dust monitors. Reflected light type, a very commonly used one, is discussed here. It normally measures the light reflected or scattered from dust instead of the light absorbed by the dust. It consists of a lamp with reflector and a photo cell receiver. They are mounted on one side of the stack as shown in Figure 3.40. The source beams the light into the duct through proper opening. Some of this light beam will get reflected by the dust particles. The reflected light is received by the photo cell and processed further. The amount of reflected light is an indication of the dust quantity present in the flue gas.

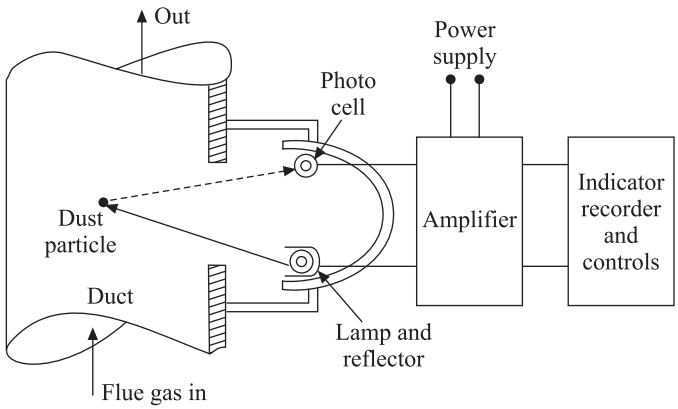


Figure 3.40 Reflected light dust monitor.

3.4.7 Closed Circuit Television (CCTV)

The closed-circuit televisions (CCTVs) are found in many applications in the thermal power plant. The important ones are:

1. Smoke or dust viewing from the chimney outlet.
2. Monitoring the drum level indication through gage glass in the control room
3. For adjusting flame in the combustion chamber
4. For scanning intruders for security reasons.

The first two applications are widely practiced in thermal power plants and the last two applications are sparingly used. Figure 3.41 explains the use of CCTVs in thermal power plants for monitoring smoke and drum water level. If the colour of the smoke is black, one can assume incomplete combustion in the furnace and combustibles are being carried away through chimney. White colour indicates complete combustion, may be with more excess air. Intermediate colours from black to white may give indications of the combustion process.

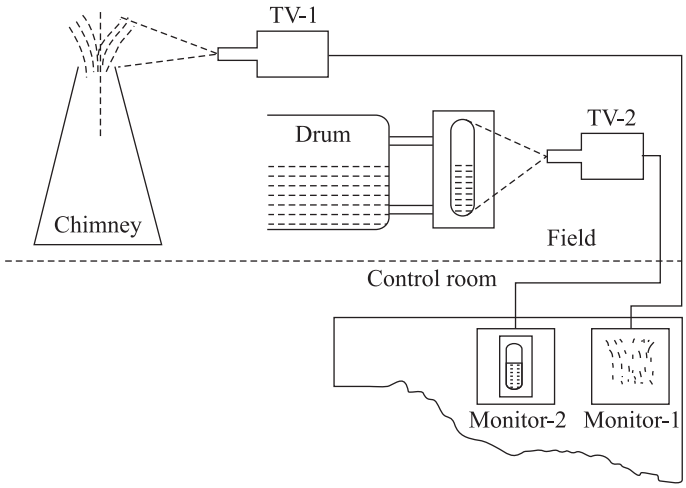


Figure 3.41 CCTVs in thermal power plant.

3.4.8 Fuel Analysers

The fuels used in the power plant are solid, liquid or gaseous in nature. In all the fuels the useful elements are carbon and hydrogen in different combinations. The fuels are required to be analysed:

1. To know the heat contents per unit volume/weight of the fuel (Calorific value) for combustion air planning
2. To know the constituents of the fuel for combustion efficiency calculation.

Calorimeter

Calorimeter is normally installed in thermal power stations for finding out heating value of the fuel that is supplied. It can be either a laboratory device or an on-line recording and indicating instrument. The units for calorific value are British thermal units per standard cubic feet (Btu/scf) or kilocalories per normal cubic metre (kcals/Nm^3).

The standard way of measuring calorific value of any fuel is to burn the fuel in a combustion chamber and note the temperature of the chamber when measured fuel and air are being supplied. The temperature of the outgoing products can be related to the calorific value of the fuel.

Calorimeters are likely to go much better for solid and gaseous fuels than for liquid fuels, which are inherently difficult to test accurately for heating value. On the other hand fuel oil is a much more homogenous substance than coal, and good estimates of heating value can be obtained from hydrometer readings.

The apparatus for heating value testing falls into two general categories, namely, continuous flow and individual sample or batch apparatus. Solid fuels are tested with individual sample apparatus, gaseous fuels by continuous flow apparatus, and liquid fuels by either type, depending on the volatility.

Coal calorimeter: The heating value of coal is determined normally by oxygen bomb calorimeter. It employs gaseous oxygen under pressure as the oxidant and electric ignition. The bomb is constructed of two pieces held together with a screwed collar. The bomb has a fuel tray, oxygen valve, two external electrical leads, and internal poles to which fuse wire can be connected. A polished container holds the bomb and about 2 kg of water. This, in turn, is surrounded by a heat insulating jacket. A stirring device is provided so that water bath will be homogeneous in temperature.

About one gram of coal is powdered and kept in the fuel tray with embedded fuse wire. The bomb is charged with oxygen to a pressure of about 15 kg/cm^2 and ignited. The temperature rise in the water due to instantaneous combustion is measured and the heating value (calorific value) of the coal interpreted.

Gas calorimeter: The calorimeter shown in Figure 3.42 is a continuous flow gas calorimeter. The fuel is burned in a steady flame with air as the oxidant. The gas flow and air flow are adjusted to a special gas burner for perfect combustion. The pilot burner is used to have continuous flame for uninterrupted burning of the test gas. The heat released after burning is absorbed by the water circulating in the tubes. The flow of water and temperature rise is measured also. With this information, the heating value of the gas can be calculated. Keeping air, gas and water flow constant, the calorific value can be assessed only with the temperature measurement.

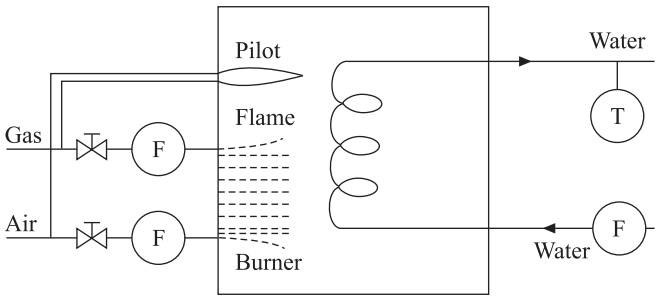


Figure 3.42 Gas calorimeter.

Fuel composition analysis

The constituents of fuel are always carbon, hydrogen, oxygen, sulphur, nitrogen, and certain mineral noncombustibles. Two forms of coal analysis are used by combustion engineers:

1. Proximate analysis
2. Ultimate analysis

Proximate analysis: This analysis is done for separation of coal into moisture, volatile material, fixed carbon and ash. This analysis is readily made by thermal means with a moderate amount of equipment. This is made by heating the coal until it decomposes successively into three of the four complex items of the proximity analysis: Moisture, volatile material and ash. Fourth, the fixed carbon is found by difference.

Ultimate analysis: The proximate analysis is of little use in combustion calculations, which are essentially chemical equations. A chemical, or ultimate, analysis is required for that kind of work. The quantitative separation of such a compound as coal into its chemical elements requires not only a well-equipped chemical laboratory, but also expert chemists.

3.4.9 Chromatography

Chromatography is a method of physical separation of components in a vapour mixture or liquid mixture. It is done based on the difference of adsorption of substances between two phases, a mobile and a stationary phase. Though chromatography is very popular in petrochemical industries, it is employed in thermal power plants to a limited scale. Chromatographs are normally used to analyse the components present in fuel. They are broadly classified into two types; namely 'gas chromatograph' and 'liquid chromatograph'. Though both are fundamentally same, gas carrier is used in gas chromatograph and liquid carrier is used in liquid chromatograph.

Gas chromatograph: On line monitoring of different components in a gaseous fuel is done by gas chromatograph in a power plant. It can also be used for flue gas analysis. It is expensive, but provides precise compositional information. In gas chromatograph, the sample gaseous mixture is transported through a column. A solid adsorbent or liquid partitioning agent is used as stationary phase. A gas is used as mobile phase. During transportation of the sample gas along with mobile phase, the stationary phase retards the various components of the sample at different rates. Adsorption, solubility, chemical bonding, polarity and molecular filtration play vital role in retardation process. The components get segregated into different zones or bands and move through

the column at different rates. The detectors are used to detect and characterize these bands at the column exit. Then the individual components produce series of signals and are recorded as chromatogram. A typical chromatogram is shown in Figure 3.43. The area under the peak represents the quantity and the time delay from injection point identifies the components.

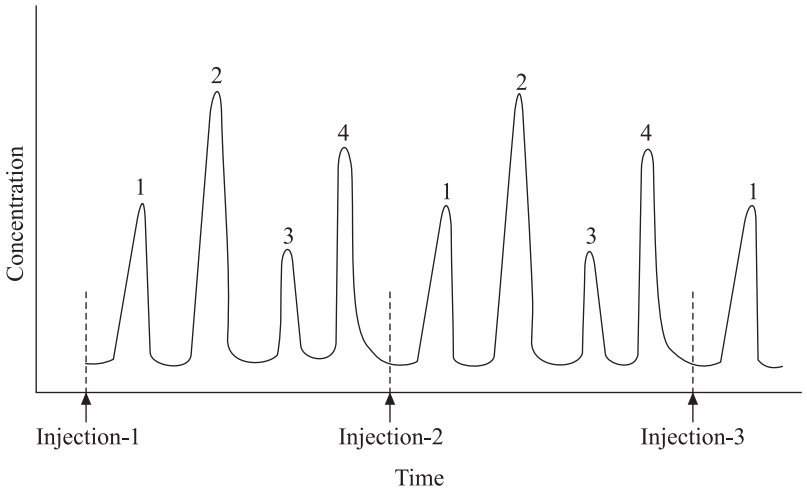


Figure 3.43 Typical gas chromatograph.

Basic parts of a gas chromatograph: Figure 3.44 shows a simple block diagram of a gas chromatograph with basic parts indicated.

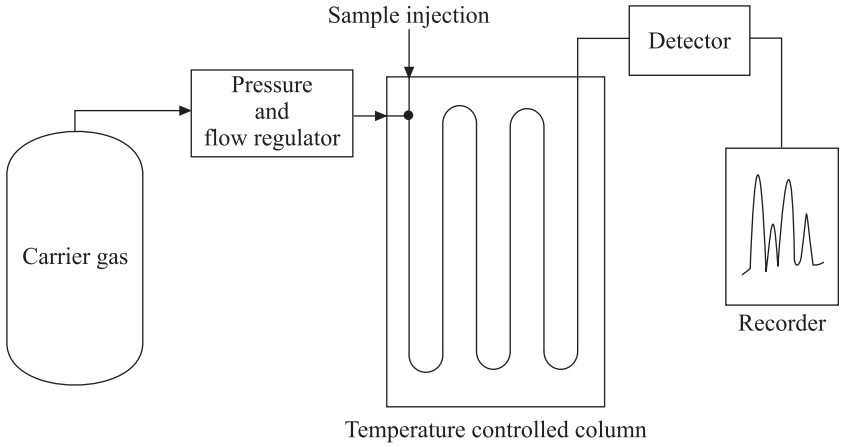


Figure 3.44 Block diagram of a gas chromatograph.

The continuous supply of carrier gas (normally N_2, Ar or He) forms the mobile phase. Carrier gas is passed from a cylinder through pressure and flow regulators to the column where it carries the sample gas injected along with it through the column. Sample gas is injected by a syringe mechanism. The sample mixes with carrier gas and passes through chromatographic

column, the heart of the chromatograph. It is here the retardation of different constituents takes place when the sample gas moves with carrier gas (mobile phase) along the solid stationary phase. The column is maintained at a temperature which decides the delay of different constituents before reaching the detector at the end of the column. The detector and recorder help to record the chromatogram.

Liquid Chromatograph: There are different types of liquid chromatographs available commercially. In this section we will briefly discuss about 'high pressure liquid chromatography' (HPLC) which is similar to gas chromatography. Here the liquid sample is forced through a column along with liquid mobile phase and the components are physically separate and detected at the end of the column. Figure 3.45 shows a simplified block diagram of liquid chromatograph.

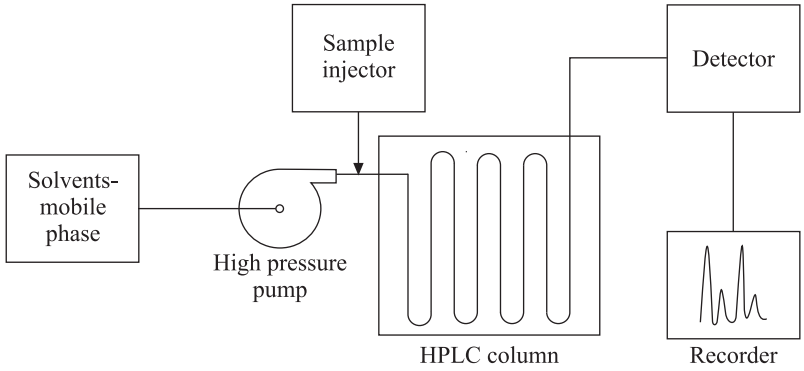


Figure 3.45 Block diagram of a liquid chromatograph.

The liquid mobile phase is forced into HPLC column by a high pressure pump. The sample injector injects sample into the column which is then carried by the mobile phase liquid. The components of the sample are physically separated in the column during their passage along the stationary phase. The detector senses these components as they come out with associated time delays and then recorded.

3.4.10 Pollution Monitoring Instruments

One encounters the following four categories of pollution while operating thermal power plant.

1. Air pollution
2. Water pollution
3. Land pollution
4. Noise pollution.

Air pollution

The exhausts from power house chimneys contain mainly CO_2, CO, N_2, sulphur, NOx and SOx. Power houses also throw fly ash, dust, coke particles and smoke into the surroundings. When some of the constituents react with moisture and air in atmosphere, they become some form of acids. When they are falling into the ground it is called *acid rain*. Acid rain causes lot of bad

effects. Gases such as carbon dioxide, methane, sulphur oxides and nitrous oxides trap heat and releases into the atmospheres. Such gases are called *greenhouse gases*. Greenhouse gases are responsible for 'global warming' and ozone layer depletion which are known as *greenhouse effect*.

The air pollution monitoring instruments are many. We have already seen how O_2, CO_2 and ($CO + H_2$) can be measured in flue gases. Smoke and dust monitors are also grouped under air pollution instruments. Techniques like infrared absorption, gas chromatography, ultraviolet absorption, mass spectrography etc. are used to measure the constituents like CO, CO_2, SOx, NOx etc.

Water pollution

Effluent discharges from powerhouses may pollute the water sources in and around them adversely. It poses health hazards to the people living in nearby places. The quantity of specific pollutants present in the water decides the quality of water. Elemental analyses, microbiological and bacteriological examinations, radiochemical analyses, etc. are used to determine the quality of water. Modern instruments for the same purpose include atomic absorption spectrometer, gas chromatograph, polar graph and thin-layer chromatograph.

Land pollution

It is the aftereffect of water pollution. The chemical or hazardous materials soluble in water are carried away and get deposited in the land nearby. The soil finally gets contaminated. Hence the treatment of effluent becomes necessary before they are let into water-streams or lands. The soil testing and groundwater testing may reveal the condition of the soil and water. Such tests are to be conducted on regular basis to make sure that the contamination level is not going beyond safe levels.

Noise pollution

No strict legislations are there for noise pollution like other pollutions. Steps are on to have legislations based on so many considerations. The identification of sound sources with time duration has to be given due considerations. Though 80 dB sound level is considered safe, 25 dB sound level only is accepted in power stations. The sound sources from power stations include FD fans, ID fans, feed pumps, turbines, alternators, crushers, coal mills and safety valves. Maximum sound levels are recorded during start-ups and shut-downs of boilers because of letting out of high pressure steam. At the time of safety valve setting one can notice a considerable increase in noise level.

WORKED-OUT PROBLEMS

PROBLEM 3.1 A type-K thermocouple (chromel-alumel) is used for measuring flue gas temperature. The reference junction (cold junction) is maintained at 50°C. Find out the millivolt available as output if the flue gas temperature (hot junction temperature) is

(a) 900ºC
(b) 600ºC

(Temperature versus millivolt standard table may be referred.)

Solution:

(a) Hot junction temperature = 900ºC
Millivolt corresponding to 900ºC with 0ºC cold junction temperature = 37.325 mV
Millivolt corresponding to 50ºC with 0ºC cold junction temperature = 2.022 mV

$\therefore$ Millivolt output = 37.325–2.022
= 35.303 mV

(b) Hot junction temperature = 600ºC
Corresponding mV = 24.902 mV

$\therefore$ Millivolt output = 24.902–2.022
= 22.88 mV

PROBLEM 3.2 What will be (a) the gauge pressure and (b) absolute pressure of combustion air of 15 metres water gauge? Express them in (i) kg/cm^2, (ii) mmWg and (iii) mmHg.

Solution:

(a) Gauge pressure

(i) Combustion air pressure = 15 mWg

$$\text{Pressure in kg/cm}^2 = \frac{15}{10} = 1.5 \text{ kg/cm}^2$$

($\because 1 \text{ kg/cm}^2 = 10 \text{ m Wg}$)

Pressure in mmWg = 15 m × 1000 = 15,000 mmWg

$$\text{Pressure in mmHg} = 15 \text{ m} \times \frac{1000}{13.546} = 1107 \text{ mm Hg}$$

(b) Absolute pressure

(i) Absolute pressure in kg/cm^2 = $\frac{15}{10}$ + Atmospheric pressure
= 1.5 + 1.03 = 2.53 kg/cm^2 abs

$\because$ Atmospheric pressure = 1.03 kg/cm^2

(ii) In mmWg = 15 × 1000 + 1.03 × 10,000
= 25,300 mmWg abs

(iii) In mmHg $= \frac{25,300}{13.546} = 1868$ mmHg

PROBLEM 3.3 A coal conveyor system moves at a speed of 450 m/min. A weighing platform is 15 m in length and a particular weighing shows a reading of 200 kg. Find the coal delivery in kg/hr

Solution: The flow rate can be calculated as

$$Q = \frac{WR}{L}$$

where

Q = Flow rate in kg/hr

W = Weight of coal on 15 m length.

L = Length of weighing platform in m

R = Conveyor speed in m/hr.

$$Q = \frac{(200 \text{ kg})\,(450 \times 60 \text{ m/hr})}{15 \text{ m}}$$

$$Q = 360000 \text{ kg/hr (or 360 T/hr).}$$

PROBLEM 3.4 The level of oil fuel in a tank of 3 m height has to be measured using a Bourdon pressure gauge located 2 m below the bottom of the tank. If the gauge is calibrated for 0 to 0.5 kg/cm^2, tabulate the oil tank level versus the pressure reading. (Assume the specific gravity of the oil is 0.9).

Solution: Let us assume the levels to be tabulated are 0 m, 0.5 m, 1 m,1.5 m, 2 m, 2.5 m and 3 m.

When the level is 0 m, the pressure experienced by the pressure gauge located 2 m below = P_O

$$P_O = \frac{2\text{m} \times 0.9}{10 \text{ m}} \text{ kg/cm}^2$$

$$= 0.18 \text{ kg/cm}^2$$

$(\because 10 \text{ mWg} = 1 \text{ kg/cm}^2 \text{ and oil specific gravity} = 0.9)$

This pressure has to be added always when other levels are measured taking the location of the pressure gauge (2 m below the tank) into consideration. Thus for 1 m level,

$$P_{1\,\text{m}} = \frac{1\text{m} \times 0.9}{10 \text{ m}} + 0.18 \text{ kg/cm}^2$$

$$= 0.27 \text{ kg/cm}^2$$

We can calculate the pressures for different levels in the same way and tabulate as below.

S.No.	Level in the tank m	Pressure reading kg/cm^2
1	0	0.180
2	0.5	0.225
3	1.0	0.270
4	1.5	0.315
5	2.0	0.360
6	2.5	0.405
7	3.0	0.450

PROBLEM 3.5 Gas flow meter is calibrated for 0–20,000 Nm^3/hr and the combustion air flow meter for 0–80,000 Nm^3/hr. If the gas fuel requires the combustion air flow for complete combustion at the ratio of 1:5, what should be the ratio set at electronic ratio station?
[Assume flow meters are calibrated to give standard electrical output signals for full range]

Solution: The fuel/air ratio 1:5 means that 1 unit of fuel requires 5 units of air. For example, if fuel gas is flowing at the rate of 10,000 Nm^3/hr, the air has to flow at the rate of $5 \times 10{,}000 = 50{,}000$ Nm^3/hr for proper combustion. The electronic ratio setter will be concerned only with electrical signal.

$$\text{Electrical signal ratio} = \frac{\text{Maximum range of fuel flow}}{\text{Maximum range of air flow}} = \frac{20,000}{80,000} = 1:4$$

$\therefore$ 1 : 4 ratio is already existing by default because of the metre calibration ranges.

Electronic ratio station's duty now is to increase 1 : 4 ratio into 1 : 5 ratio. That means it should have 1 : 5/4 = 1 : 1.25 ratio (Refer to Figure 3.46. for better understanding).

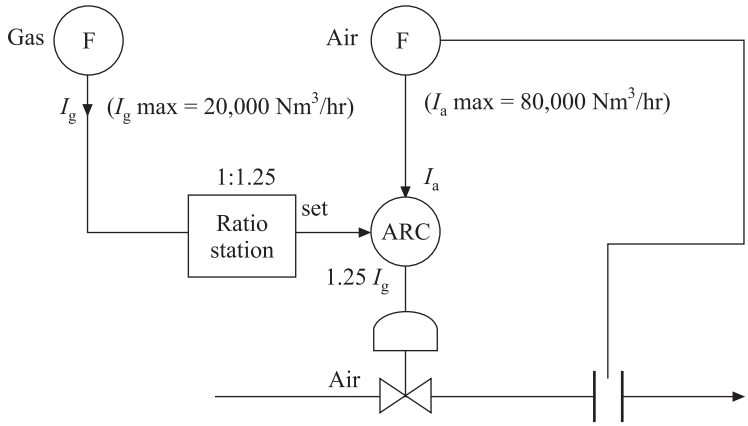


Figure 3.46 Schematic for Problem 3.5.

Note: I_g max = I_a max
For any I_g, I_a = 1.25 I_g to statisfy air-fuel ratio requirement of 1 : 5.

PROBLEM 3.6 The capacity requirement of an ID fan in a coal fired boiler is 100 HP when air is used for combustion. What will be the capacity requirement of ID fan if oxygen is directly used for combustion?
Assumptions:

(a) Flue gas volume is not affected by the amount of coal burnt, but is directly proportional to air or oxygen volume.
(b) ID fan capacity is directly proportional to the square of the flue gas volume handled.

Solution: Let Q_1 be the volume of flue gas handled per unit time when air is used for combustion. Then,

$$100\ HP \propto Q_1^2$$

$$100 = \mathrm{K}Q_1^2$$

Let Q_2 be the volume of flue gas handled per unit time when oxygen is used for combustion.

$$\frac{Q_2}{Q_1} = 0.21 \qquad [\because \text{\% oxygen present in air is 21}]$$

New $HP = KQ_2^2$

$$= K\,(0.21\,Q_1)^2$$

$$= \frac{100}{Q_1^2} \times 0.21^2 \times Q_1^2$$

$$= 4.4 \text{ HP}$$

PROBLEM 3.7 Steam atomisation is used for burning oil in a boiler. Design a proper scheme to satisfy the following conditions for burning oil efficiently.

Atomising steam pressure to oil pressure ratio should be maintained at 1:1.5. Fuel oil should be cut-off completely if the ratio falls below 1.

Solutions: Figure 3.47 shows the required schematic which is self-explanatory.

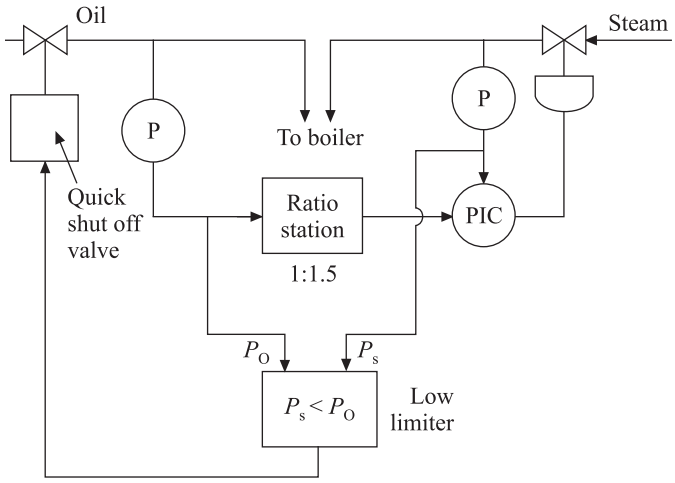


Figure 3.47 Schematic for Problem 3.7.

As long as atomizing steam pressure (P_s) is higher than oil pressure (P_O), the low limiter will output *O* signal. When P_s goes below P_O, the low limiter will output *H* signal which will actuate a solenoid of a quick shut off valve to cut off oil supply

PROBLEM 3.8 The gas holder used for storing gas fuel for a power plant is provided with a disc of 2000 kg. The height and area of cross section of the holder are 60 m and 10 m^2.

(a) What is the operating pressure maintained by the gas holder?
(b) How long does it require to fill up the tank from 5 m level when consumption has stopped and the source is supplying gas at the rate of 100 m^3/minute at the operating pressure?

Solution:

(a) Operating pressure maintained by gas holder = P_O

$$P_O = \frac{\text{Weight of the disc}}{\text{Area of cross section of the gas holder}}$$

$$= \frac{2000 \text{ kg}}{10 \text{ m}^2} = \frac{2000 \text{ kg}}{10 \times 10^4 \text{ cm}^2}$$

$$= 200 \times 10^{-4} \text{ kg/cm}^2$$

$$= 200 \times 10^{-4} \times 10{,}000 \text{ mmWg}$$

$$= 200 \text{ mmWg}$$

(b) Initial level = 5 m
Full level = 60 m
To raise the level to full, the volume of gas required = Area × effective height

$$= 10 \text{ m}^2 \times (60 - 5) \text{ m}$$

$$= 550 \text{ m}^3$$

Rate of incoming gas = 100 m^3/min

$$\therefore \text{ Time taken to fill up the tank} = \frac{550 \text{ m}^3}{100 \text{ m}^3/\text{min}}$$

$$= 5.5 \text{ min.}$$

EXERCISES

1. What are the different fuels used in a thermal power plant?
2. If the range of air flow meter and gas flow meter are 0 – 5000 Nm^3/hr and 0–400 Nm^3/hr, find out the ratio to be set in a fuel-Air ratio station to get 1:6 fuel-air ratio for combustion.
3. What is the function of a ratio station in combustion control system?
4. What are the two ways of atomising oil fuel?
5. Why do we measure O_2 in flue gas?
6. Name four different drafts in connection with operation of boilers.
7. What will happen if furnace pressure is (i) too negative and (ii) too positive?
8. Explain a combustion control system with air-fuel parallel operation and cross limited providing air and fuel limiting facilities for safety purposes.
9. Explain with schematic diagram the furnace pressure control in a boiler designed for balanced draft operation.
10. What is meant by trimming of combustion control system?
11. What are the different uses of closed-circuit TV in a thermal power station?
12. What are the different pollutions we encounter in thermal power plant operation?

13. Write down the different principles used for analyzing the following in flue gas.

(i) O_2 (ii) CO_2
(iii) $(CO + H_2)$ (iv) CO

14. What is chromatography? Differentiate gas chromatography and liquid chromatography.

15. Explain the operation of a:

(i) Smoke monitor and
(ii) Dust monitor

16. Calculate the operating pressure in a gas holder if the area of cross section of the holder is 10 m^2 and the weight of the disc is 15,000 kg.

17. Differentiate single point positioning and parallel positioning control of combustion control.

18. The power station having 1200 MW rated capacity is serviced by 6 boilers of equal capacity. At one point of time they are derated as follows:

Boiler # 1: 90%
Boiler # 2: 60%
Boiler # 3: Shutdown
Boiler # 4: 85%
Boiler # 5: Full capacity
Boiler # 6: 80%

What will be the maximum power which can be generated by the power station?

19. What is draft pressure? How is it controlled?

20. For trimming of combustion control system, what are the parameters to be measured?

21. What is series fuel type of combustion control?

22. Name the temperature sensors for the following applications in a boiler:

(i) Flue gas temperature (0–900ºC)
(ii) Economiser outlet temperature (0–300ºC)
(iii) Stack temperature (0–100ºC)
(iv) Flame temperature (> 1000°C)

23. Describe the basic elements of pulverized coal system.

24. What are the objectives of combustion control?

25. How a furnace draft can be measured accurately?

26. Write briefly on air flow control.

27. Discuss the combustion control of liquid and gaseous fuel boilers.

28. Why atomization is required while burning oil fuel?

29. What is the maximum temperature obtained in furnace used in power plants?

30. Draw and explain flue gas flow diagram.

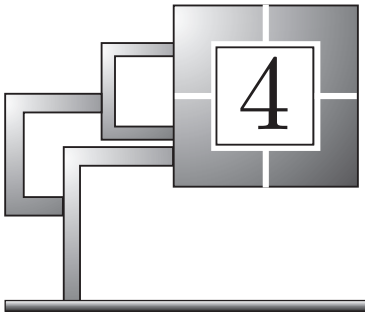
31. Give names of liquid and solid fuels used for boilers.

32. What are the ranges of pressure encountered in fuel-air circuit of a boiler?

33. How the air flow, pressure and temperature are measured in boilers?

34. Differentiate 'extractive method' and 'in situ sampling method' of flue gas analysis?

35. What are the different modes of burning coal in a boiler?



Power Plant Management

4.1 INTRODUCTION

Power plant management is necessary to monitor the operation of the plant, besides it plays a pivotal role in improving its efficiency. Fuel management and thermal system management for evaluating the performance to get better thermal efficiency are required. Also data logging of a large number of parameters and analysis of critical parameters will lead to better management of the plant. The topics covered in this chapter include master control and load-sharing control, combustion process, efficiency calculations, distributed control system, supervisory control and data acquisition (SCADA), and interlocks. As the above topics are more relevant to the power plant as a whole than to individual boilers, they are all grouped together and discussed in this chapter. Maintenance and calibration of instruments will also find a place as a part of power plant management.

4.2 MASTER CONTROL

Master control for a power station is a common one for all boilers. The idea behind this control is to supply enough steam to the turbines for meeting the electrical load demand of the power station. Whenever there is a change in electrical load, there will be a change in turbine load, hence the change in demand for steam supply from boilers. This change in demand for steam has to be shared by all the boilers in operation as per their conditions. The change in steam demand of a particular boiler has to be met by change in combustion rate. Hence air and fuel changes become necessary. Correspondingly the FD fan and ID fan controls act to satisfy the draft requirements.

To implement effectively the above requirements in a power station, a single measureable parameter has to be selected which is more relevant for the purpose of master control. It may be electrical load, steam temperature, steam flow rate or common steam bus pressure. But the commonly used parameter is steam pressure. The following discussions are based mainly on the assumption that steam pressure is taken as master control parameter.

Normally in a power station, a number of boilers and turbines may be in operation. The output steam from all the boilers will be collected in a common bus (or main). It becomes necessary to maintain the bus pressure constant for efficient operation of the turbines. The rate of steam consumed by all the steam turbines put together and the mains steam pressure are interlinked. When the turbine load increases, the demand for steam and the steam flow increases and as a result the steam pressure decreases. If one to one combination (one boiler to one turbine) is practiced, the parameter used for combustion control may be either steam flow or steam pressure. Where parallel operation of boilers and turbines is followed as shown in Figure 4.1, it is always a common practice to use steam pressure as the controlled variable. Also the total steam flow measurement is not practicable in a bus system.

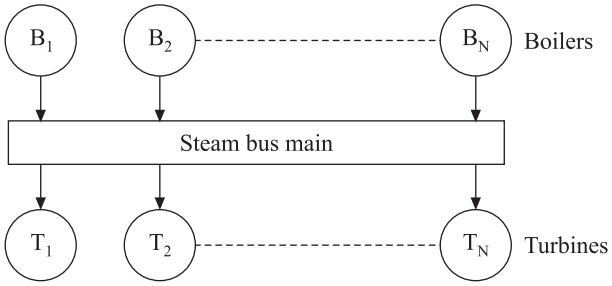


Figure 4.1 Steam bus operation.

Generally a power station will operate with a help of a 'master controller' whose function is to compare the steam bus pressure with the set point and send signals to different boilers as 'firing rate demand'(FRD). Firing rate demand is sometimes called *fuel demand* or *air demand*. Depending upon the boiler conditions, the load-sharing controllers of different boilers will share the master controller signal. For example, at any point of time if boiler-1 is capable of taking full load and boiler-2 is capable of taking only 50% of its full load, the load sharing ratio between boiler #1 and boiler #2 will be 2:1. The same argument may be extended to other boilers also. By chance if any boiler is under annual shutdown, its share will be 0%. A simple schematic of the master controller of the power station and the load-sharing controllers of the individual boilers are shown in Figure 4.2. The output of the load-sharing controller becomes firing rate demand for the combustion control system for the particular boiler. Further combustion control processes have already been discussed in Chapter 3 elaborately.

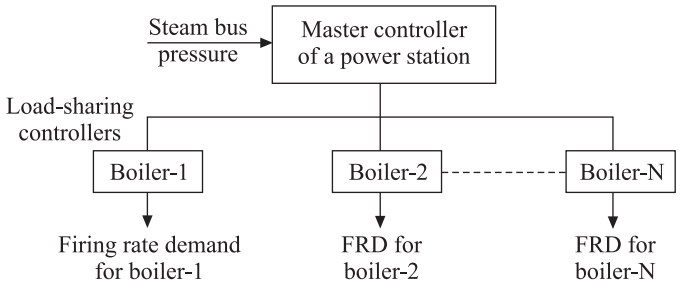


Figure 4.2 Master and load-sharing controls.

4.3 COMBUSTION PROCESS

The chemical elements like carbon, hydrogen and sulphur contained in the fuel, combine with oxygen in the air to produce combustion. To start and continue combustion the combustion chamber temperature has to be always more than the ignition temperature of the fuel being burned. During combustion, the heat energy is liberated at high temperature. The resultant gaseous mixture produced after combustion process is called *hot flue gases*. The fuels used may be in the form of solid (coal), liquid (fuel oil) or gas (natural gas or process gases).

4.3.1 Heat of Combustion/Calorific Value

The heat of combustion of various elements are expressed in kcals/kg or kcals/Nm^3 as given in Table 4.1

Table 4.1 Calorific values of various elements

Element	Calorific value kcals/kg	Calorific value kcals/Nm^3
Carbon (C)	7,830	—
Hydrogen (H_2)	33,947	2,892
Carbon monoxide (CO)	2,415	2,865
Sulphur (S)	2,213	—
Methane (CH_4)	13,267	9,015
Ethane (C_2H_6)	12,401	15,947

4.3.2 Basic Chemical Equations of Combustion

The following are the basic chemical equations of the combustion process. The carbon burns with oxygen to become carbon dioxide. If sufficient oxygen ions are not available either due to insufficient air or due to non-homogeneous mixture, carbon monoxide is produced as an intermediate compound.

$$C + O_2 \rightarrow CO_2$$

$$2C + O_2 \rightarrow 2CO$$

$$2CO + O_2 \rightarrow 2\,CO_2$$

For H_2 combustion:

$$2H_2 + O_2 \rightarrow 2H_2O$$

For sulphur combustion:

$$S + O_2 \rightarrow SO_2$$

For methane and ethane combustion:

$$CH_4 + 2O_2 \rightarrow CO_2 + 2H_2O$$

$$2C_2H_6 + 7O_2 \rightarrow 4\,CO_2 + 6H_2O$$

Figure 4.3 shows in a nutshell the above reactions.

The following are the fundamental requirements for a proper combustion process.

1. Thorough mixing of fuel and air in correct proportion which will ensure complete combustion.

2. Exposure of fuel particles to oxygen throughout a period of time sufficient for their combustion.
3. Combustion zone maintained above the ignition temperature of the fuel always.

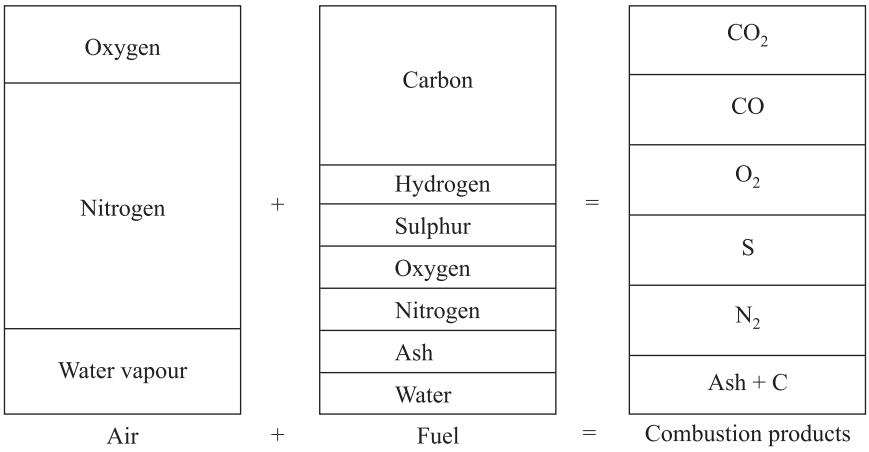


Figure 4.3 Basic combustion process

Ignition temperature of a combustible is the minimum temperature at which combustion takes place in the presence of oxygen. The ignition temperature of the elements of our interest is tabulated in Table 4.2.

Table 4.2 Ignition temperature

Element	Ignition temperature
Sulphur	243°C
Carbon	466°C
Hydrogen	580°C
Carbon monoxide (CO)	610–657°C
Methane (CH_4)	632–749°C
Ethane (C_2H_6)	471–629°C

If the combustible substances are totally burned with exact quantity of oxygen then 'perfect combustion' would have been achieved. The quantity of air that can provide such an oxygen quantity is called 'Theoretical air' or 'Stoichiometric air'. In practice, perfect combustion is not possible. Hence excess of oxygen in the form of 'excess air' is always provided to achieve almost perfect combustion. The amount of excess air varies with fuel, firing equipment (burners) and load. Apart from adequate air supply, the three Ts, viz., time, temperature and turbulence have to be kept in mind while designing the furnace.

4.3.3 Combustion Calculations

Combustion calculations assist the boiler designer in calculating the quantities of fuel and air required for a given steam output from a boiler. Calorimeters are used to directly find out the

calorific values of fuels. Otherwise computation from the chemical analysis of fuel may be done using Dulong's formula given below.

$$\text{Calorific value in kcals/kg} = 7830\,C + 33950\left(H_2 - \frac{O_2}{8}\right) + 2210\,S$$

The term $\frac{O_2}{8}$ is a correction applied to the hydrogen in the fuel to account for the hydrogen already combined with oxygen in the form of moisture. If we consider the burning of carbon to carbon dioxide, the number of atoms before and after the reaction must balance and hence the weights of the elements entering the reaction must be equal to the weights of the products of reaction or combustion. Thus we have:

$$C + O_2 = CO_2$$

$$12 \text{ kg} + 32 \text{ kg} = 44 \text{ kg} \quad \text{(Molecular weight)}$$

Dividing by 12, we get

$$1 \text{ kg} + 2.67 \text{ kg} = 3.67 \text{ kg}$$

If the weight of the carbon used is C kg, then

$$C \text{ kg} + 2.67\,C \text{ kg} = 3.67\,C \text{ kg which means}$$

C kg of carbon takes 2.67 C kg of oxygen to produce 3.67 C kg of carbon dioxide after combustion. The carbon, which is originally solid, reacts with oxygen, a gas, and produces carbon dioxide, a gas.

In case of incomplete combustion carbon monoxide is produced. Thus we have:

$$2C + O_2 = 2\,CO$$

$$24 \text{ kg} + 32 \text{ kg} = 56 \text{ kg}$$

Dividing by 24, we get

$$1 \text{ kg} + 1.33 \text{ kg} = 2.33 \text{ kg}$$

$$C \text{ kg} + 1.33\,C \text{ kg} = 2.33\,C \text{ kg}$$

The following is true for burning hydrogen.

$$2H_2 + O_2 = 2H_2O$$

$$4 \text{ kg} + 32 \text{ kg} = 36 \text{ kg}$$

$$1 \text{ kg} + 8 \text{ kg} = 9 \text{ kg}$$

$$1H_2 \text{ kg} + 8H_2 \text{ kg} = 9H_2 \text{ kg for } H_2 \text{ kg of hydrogen.}$$

Considering sulphur we have:

$$S + O_2 = SO_2$$

$$32 \text{ kg} + 32 \text{ kg} = 64 \text{ kg}$$

$$1 \text{ kg} + 1 \text{ kg} = 2 \text{ kg}$$

$$1S \text{ kg} + 1S \text{ kg} = 2\,S \text{ kg for } S \text{ kg of sulphur.}$$

If it is methane we have:

$$CH_4 + 2O_2 = CO_2 + 2H_2O$$

$$16\ \text{kg} + 64\ \text{kg} = 44\ \text{kg} + 36\ \text{kg}$$

$$1\ \text{kg} + 4\ \text{kg} = 2.75\ \text{kg} + 2.25\ \text{kg}$$

$$1\ \text{M kg} + 4\ \text{M kg} = 2.75\ \text{M kg} + 2.25\ \text{M kg}$$

where M = weight of methane burned.

The molecular weights of different elements which are of interest to us are tabulated in Table 4.3

Table 4.3 Molecular weights

Element	Molecular weight
Oxygen (O_2)	32
Carbon (C)	12
Carbon monoxide (CO)	28
Carbon dioxide (CO_2)	44
Hydrogen (H_2)	2
H_2O	18
Sulphur (S)	32
SO_2	64
Nitrogen (N_2)	28

4.3.4 Molar Analysis

The molecular weight of an element is denoted as 'mol' and the volume it occupies is called 'molal volume'. Molal volume varies with temperature and pressure according to gas laws. The volume of one kg mol of an ideal gas at 0ºC and 760 mmHg is 22.4 m^3. In one mol of air there is 0.21 mol of oxygen and 0.79 mol of nitrogen for all practical purposes. By weight, the oxygen content in one mol of air is 0.21×32 (= 6.72), that of nitrogen is 0.79×28 (= 22.12) and hence that of air is 6.72 + 22.12 (= 28.84). Hence

$$\text{Percentage by weight of oxygen in air} = \frac{6.72}{28.84} \times 100 = 23\%$$

$$\text{Percentage by weight of nitrogen in air} = \frac{22.12}{28.84} \times 100 = 77\%$$

Let us consider the combustion equations for carbon and hydrogen for understanding purpose.

$$C + O_2 \rightarrow CO_2$$

$$1\ \text{mol C} + 1\ \text{mol } O_2 = 1\ \text{mol } CO_2$$

$$2H_2 + O_2 \rightarrow 2H_2O$$

$$2\ \text{mols } H_2 + 1\ \text{mol } O_2 = 2\ \text{mols } H_2O$$

Thus one molecule of carbon plus one molecule of oxygen gives only one molecule of carbon dioxide. Similarly two molecules of hydrogen plus one molecule of oxygen gives two molecules

of water vapour. Since a mol represents a definite weight as well as a definite volume, it can be used as a means of converting 'analysis by weight' into 'analysis by volume' and vice versa.

4.3.5 Theoretical or Stoichiometric Air Requirement

Theoretical air requirement for complete combustion can be calculated by finding out first the oxygen requirement.

For carbon:

C = Weight of carbon in kg

Oxygen required for complete combustion is:

$$C \times \frac{32}{12} = C \times \frac{8}{3} \text{ kg} = 2.67 \text{ Ckg}$$

For hydrogen:

H_2 = Weight of hydrogen in kg

$$\text{Oxygen required} = H_2 \times \frac{32}{2 \times 2} = H_2 \times 8 \text{ kg}$$

$$= 8\ H_2 \text{ kg}$$

For sulphur:

S = Weight of sulphur in kg

$$\text{Oxygen required} = S \times \frac{32}{32} = S \text{kg}$$

If the fuel contained C kg of carbon, H_2 kg of hydrogen, S kg of sulphur and O_2 kg of oxygen, then the total oxygen (theoretical oxygen) required for complete combustion is given by the equation:

$$\text{Total } O_2 = (2.67\ C + 8\ H_2 + S - O_2) \text{ kg}$$

$$\therefore \quad \text{Theoretical air required} = \frac{\text{Theoretical oxygen}}{0.23} \text{ kg}$$

$$= \frac{2.67\ C + H_2 + S - O_2}{0.23} \text{ kg}$$

4.3.6 Excess Air Requirement

Complete combustion of fuel cannot be achieved if only the theoretical or stoichiometric air is supplied. Excess air is always needed for complete combustion. The amount of excess air varies with fuel used, operational load and the firing equipment (burners). It is expressed as a percentage of theoretical air or by the use of a dilution coefficient.

$$\%\text{excess air} = \frac{W_A - W_T}{W_T} \times 100\%$$

where

W_A = The actual amount of air supplied

W_T = Theoretical air required.

The dilution coefficient, *d*, is given by

$$d = \frac{W_A}{W_T}$$

The percentage of excess air varies from 3 to 40% as given in Table 3.1 for different fuels.

4.3.7 Products of Combustion

The flue gas generated after combustion of fuel will contain CO_2, H_2O and SO_2 in addition to N_2 present in the air and the fuel. The weights of the combustion products can be calculated as below.

$$\text{Weight of } CO_2 = C + 2.67\ C = 3.67C \text{ kg}$$

$$\text{Weight of } H_2O = H_2 + 8\ H_2 = 9\ H_2 \text{ kg}$$

$$\text{Weight of } SO_2 = S + S = 2S \text{ kg}$$

$$\text{Weight of } N_2 = (N_2 + \text{Theoretical air} \times 0.77) \text{ kg}$$

The combustion products can be expressed by volume as below:

$$\text{Volume of } CO_2 = \frac{\text{Weight of } CO_2}{\text{Molecular weight of } CO_2} \times 22.4 \text{ m}^3$$

$$= \frac{3.67\ C}{44} \times 22.4 \text{ m}^3$$

$$\text{Volume of } H_2O = \frac{9H_2}{18} \times 22.4 \text{ m}^3$$

$$\text{Volume of } SO_2 = \frac{2S}{64} \times 22.4 \text{ m}^3$$

$$\text{Volume of } N_2 = \left(\frac{N_2 + \text{Theoretical air} \times 0.77}{28}\right) \times 22.4 \text{ m}^3$$

4.4 BOILER EFFICIENCY

Though boiler efficiency refers to the heat input given to feed water by the furnace and the heat content of the superheated steam coming out of the boiler, the overall thermal efficiency of the boiler is the product of furnace efficiency and boiler efficiency. That means, the percentage of the higher heating value of the coal or fuel which will be present in the outlet steam is overall thermal efficiency which is usually, though wrongly, called *boiler efficiency*. Typically the efficiency varied from 60 to 75%. With economiser and air preheater, it can be improved to 70 to 85%. With modern equipment and advanced control system in position, the boiler efficiency can be increased to 80 to 90%.

4.4.1 Calculation of Boiler Efficiency

If the heating value of fuel is completely transferred to feed water for generating steam, the boiler efficiency will be cent percent. It is not possible because of the losses occurring

during the process. The heat losses in the boiler operation is grouped into seven components as described below.

1. **Heat loss due to dry chimney gas:** The loss is due to raising the dry chimney gas from atmospheric temperature to flue gas temperature. The causes are attributed to:
   (a) High excess air as revealed in low CO_2 content of flue gas
   (b) High flue gas temperature due to:
      (i) Dirty heating surfaces
      (ii) Poor water circulation due to scale formation in water side
      (iii) Dead gas pockets due to leaky or ineffective baffles.
      (iv) Gas velocity too high
2. **Heat loss due to moisture in fuel:** This loss is due to boiling off the moisture in the fuel and superheating to flue gas temperature. The causes are attributed to:
   (a) Excessive wetting down of coal before firing
   (b) High moisture absorbtion by coal in the storage yard.
3. **Heat loss due to H_2O from combustion of H_2:** This loss is due to forming water vapour from free H_2 in the fuel and superheating the flue gas temperature. The cause for this loss is due to moisture formed by combustion of hydrogen. Irreducible for any specific fuel, this loss is larger for oil and gas fuels than for coal.
4. **Heat loss due to incomplete combustion:** (Indicated by the presence of carbon monoxide in the flue gas). This loss is due to failure to realize the full heat of formation of carbon and oxygen. The causes are attributed to:
   (a) Insufficient air supply
   (b) Fuel bed in poor condition
   (c) Undercooling of furnace at low ratings
   (d) Inproper setting of boilers
5. **Heat loss due to combustibles in refuse or ash pit:** This loss is due to loss of potential heating value represented by the presence of unconsumed combustible in the ash refuse. The causes are attributed to:
   (a) Grate or stoker is not proportioned to the kind of fuel used
   (b) Too high rate of combustion attempted
   (c) Grates dumped or fuel bed sliced too frequently
   (d) Furnace temperature is above fusion temperature of ash.
6. **Heat loss due to radiation and convection from boiler and setting:** This loss is due to heat transfer from the setting to the ambient atmosphere by the process primarily of radiation, with some secondary induced convection. The losses are attributed to:
   (a) Boiler drum uninsulated
   (b) Wall of setting too thin or of poor quality
   (c) Furnace refractories in need of repair or relining.

7. **Heat loss unaccounted:** This loss is a miscellaneous group of relatively small magnitude, frequently not measurable. The causes are attributed to:
   (a) Moisture in the air for combustion
   (b) High excess air on days of high humidity
   (c) Several other small losses due to soot or cinder in the chimney gas and heat in ashes.

The heating value of the fuel used minus the heat usefully absorbed by the unit (the heat content of the steam produced) may be equated to the seven losses described above. The first five of the losses are calculable from flue gas analysis, temperatures, refuse analysis and fuel analysis. There are two methods of procedure for jointly determining the other items, depending on which one is found by the difference between the heating value of the fuel used and the heat absorbed by the unit plus the other six losses. Calculation of the different losses finally helps the operator to identify the sources of the loss and rectify them to achieve maximum efficiency.

There are two ways of calculating boiler efficiency. They are:

1. Input-output method
2. Heat balance or heat loss method.

Input-output method

In this method the rate of steam generation is determined by steam flow meter. Time of test and weight of fuel used during that period are kept. Knowing by fuel analysis, the heat content of the fuel used and calculating the heat absorbed by the unit, that is, the heat content of the steam produced, the efficiency can be calculated.

$$\text{Boiler efficiency} = \frac{\text{Heat content of the steam}}{\text{Heat content of the fuel used}} \times 100\%$$

This method is normally recommended because the output-input relationship is considered as the more direct route to efficiency.

Heat balance or heat loss method

As it is very difficult to accurately calculate the heat content of the steam produced, this method makes use of the information of the total losses (7 losses described above) for calculating efficiency

$$\text{Boiler efficiency} = \frac{\text{Heat content of the fuel used} - \text{Total of the 7 losses}}{\text{Heat content of the fuel used}} \times 100\%.$$

Here it is quite important to conduct a test at a steady rate of steam generation and fuel feed. To achieve the highest possible efficiency, small manual adjustment of the fuel-air ratio set by automatic control may be required. Repeated checks of flue gas composition test the value of these adjustments. Steady output can be maintained if the boiler is part of a system containing other boilers which may be forced to carry all the variable part of the system load. An isolated unit should be provided with an atmospheric discharge line having a conveniently located hand valve. Then steam may be wasted at variable rate during the test in order to compensate for variable demand on the plant and thereby hold boiler steaming rate constant.

The boiler is brought up to a stable uniform operating condition by several hours of preliminary operation before the data collection starts. The average of readings for one or more hours of operation is then used to calculate all the losses and the heat content of steam is found by difference.

It is always preferable to calculate the efficiency by both methods and see that they are agreeing within limits. Both input-output method (or direct method) and heat-loss (or heat balance) method are useful, but it is generally agreed that the heat-loss method provides more accurate results. The input-output or direct method is more easily understood and for that reason is often preferred.

Blow down flow is assumed negligible in the above efficiency for direct method. It is felt that the heat carried away by blowdown flow is to be taken into account as because the efficiency calculated is only thermal efficiency. Hence the formula can be rewritten in this case as:

$$\text{Efficiency} = \frac{\text{Heat added to incoming feed water}}{\text{Heat input (fuel)}}$$

where

$$\text{Heat added} = (\text{Steam flow})(\text{Steam enthalpy} - \text{Feed water enthalpy}) + (\text{Blowdown flow})(\text{Blowdown enthalpy} - \text{Feedwater enthalpy})$$

$$\text{Heat input} = (\text{Fuel flow})(\text{Fuel higher heating value})$$

In this formula, the output of the boiler is credited with all the heat that is added to the incoming feed water. This heat added includes the non-useful heat added to the blowdown flow in increasing its temperature from feed water temperature to the saturation temperature of the boiler water.

This formula is based on knowledge of the flows of steam from the boiler, feed water to the boiler, the flow of fuel to the boiler, and blowdown from the boiler. In addition, the unit heating value of each of these flows must be known. All the flows mentioned above can be determined from flow meters. If the steam flow alone or feed water flow alone is known, blowdown flow can be determined from the 'Thermodynamic properties of steam and water' tables or a computer program. The heat content of the fuel must be determined by the use of a fuel calorimeter.

A minimum of three flows are used in this method. The potential for erroneous results because of flow meter inaccuracy is the primary weakness of this method. It is also normal that a steam, water, or fuel flow meter may not be operating at its design condition of pressure, temperature, specific gravity, etc. Unless particular care is taken in correcting the flow meter results to design conditions, further inaccuracies can easily be introduced.

The heat-loss method involves a number of measurements and a much more involved calculation than the input-output method. Because of the manner in which measurements are used in the calculations, measurement errors do not cascade as in the input-output calculation method.

4.5 MAINTENANCE OF MEASURING INSTRUMENTS

The purpose of maintenance is to:

1. Keep instruments in a condition that ensures their effective and efficient operation.
2. Keep the costs low of 'lost time' due to breakages or malfunctioning of instruments.
3. Ensure the quality of the steam by reliable readings of the instrument (by regular calibration)

4.5.1 Types of Maintenance

The maintenance activity of the instruments can be broadly divided into the following six types:

1. Routine/Running maintenance.
2. Preventive maintenance
3. Periodic/shut down maintenance
4. Break down or corrective maintenance
5. Predictive or condition-based maintenance
6. Calibration and testing

Routine/running maintenance

This type of maintenance has to be carried out every shift or every day. The typical examples of such maintenance are:

1. Ink filling in the pens of the recorders
2. Chart papers changing in the recorders
3. Timings adjustments in the recorders/printers
4. Checking of previous day's alarm conditions and attending to it
5. Checking of alarm annunciation systems
6. Checking the condition of alarm bulbs, hooter etc.
7. Checking of sampling points of critical analysers
8. House-keeping of the control panels and control rooms.

Preventive maintenance

The term preventive maintenance is used to describe maintenance which is used to delay or prevent breakdown. It involves inspection to determine which components need replacing or repair before they reach the breakdown point. Preventive maintenance is a policy of replacing components that are nearing the end of their life before they actually wear out and fail. It is a policy of anticipating failure. It also involves servicing, i.e. routine cleaning, lubrication, adjustment, etc., to reduce wear and hence prevent breakdown. It is necessary with such maintenance to keep maintenance records, indicating when inspection, servicing, repairs and replacement were carried out. Such records are necessary to ensure that servicing has been carried out at the correct times and to enable components to be replaced just before they can be expected to wear out.

Periodic/shutdown maintenance

Every boiler plant will have annual shutdown maintenance plan. During that period, maintenance of measuring instruments are also to be planned. Thorough overhauling of control drives and valves, recorders and printers etc. and calibration of indicators, recorders, transducers in addition to maintenance will be taken up during the maintenance period. Identified worn out parts, beyond repair instruments etc. can be changed totally during this period. The shutdown maintenance activities are to be planned, for example spare parts must be arranged and manpower availability is ensured well in advance. The planning has to be done based on previous experience and recommendations from instruments manufacturers. The time frame should match with that of the main plant shutdown maintenance activities.

Breakdown or corrective Maintenance

The term breakdown or corrective maintenance is used to describe a maintenance policy which is to replace or deal with failure only when it occurs. It involves the detection, location and repair or replacement of faulty items as they occur. It is a policy of waiting for failure before taking any action. It is not considered a healthy maintenance practice. Sometimes, because of the failure of one critical instrument, the whole plant process may come to a halt causing huge lost time cost.

Predictive or condition based maintenance

Though it is mostly applied to the large machines and mechanical equipment, it can also be practised to some extent in instrumentation maintenance. Knowing the life cycle of instruments, critically observing external parameters, and considering the criticality of the instrument, a plan can be made to change the instrument even if it is working at the time of changing. This is to avoid the failure of such instrument surprisingly and cause a lot of production loss to the unit.

Calibration and testing

This category of maintenance is special to instruments. One may feel from the reading of the instrument that it is working alright. If it happens to read more or lesser than the actual value, one can imagine the consequences followed with reference to quality of the product and hence the business loss. Thus it becomes essential for an instrumentation engineer to chart out a plan for testing and calibration of instruments. The frequency may be fixed based on the experience, manufacturer's recommendation and criticality of the measuring parameter in the process.

4.5.2 Maintenance Costs

The total cost of maintaining an instrumentation system can be considered to be made up of the costs of all the above six categories plus the cost of lost-time due to breakdown. The cost of maintenance, other than that of preventive and breakdown maintenance is considered almost constant. Thus the main analysis to keep the maintenance cost minimum will consider the cost of preventive maintenance, breakdown maintenance and lost-time cost.

Preventive maintenance cost

The greater the amount of preventive maintenance the greater the cost. Having preventive maintenance more than what is required for may cost more at the end.

Breakdown maintenance cost

The greater the amount of preventive maintenance the smaller the number of breakdowns and hence the smaller the cost of break down maintenance.

Lost-time cost

When an instrument or an item of it breaks down, it can no longer be used while it is replaced or repaired. This might mean that a production process has to be stopped. Such a loss in production has a cost. There are thus costs associated with the time lost as a result of breakdown. The greater

the amount of preventive maintenance, the smaller the number of breakdowns and hence, the smaller the lost-time costs.

The total maintenance cost is the sum of the costs of the four elements. The total cost is minimum at a particular level of maintenance. This is obviously the level of maintenance to adopt in order to ensure minimum costs.

4.5.3 Life Cycle Costs

The life cycle costs are the total costs of an item involving throughout its life. This includes its initial cost, its maintenance cost and any other costs involved in keeping it going. In trying to keep the life cycle costs down to a minimum, consideration has to be given to:

1. How long the instrument will last?
2. How reliable it is, i.e., how often it is likely to break down?
3. How much maintenance it requires?
4. How long it will take to carry out maintenance?
5. How easy it is to get its spare parts?

In deciding the instrument, consideration has to be given to not only the need for the instrument to carry out the required measurement but also for reliability and ease of maintenance. Erection, commissioning and calibration of the instruments need a careful planning to ensure the correct usage and a maximum life possible. Maintenance needs planning to ensure that it is at a minimum cost. The term 'terotechnology' is used for all the activities involved in trying to keep life cycle costs down to a minimum.

4.5.4 Maintenance Manuals

Whenever an instrument is purchased, it is essential to get operating instructions manual and service/maintenance manual. Many times, both are combinely supplied by the manufacturer in a single volume. The manual is likely to include the following features:

1. A description of the instrument and its use.
2. A performance specification: This could include such details as the ranges of an instrument, its accuracy and the conditions under which it is expected to be used.
3. Calibration details and the standard instruments needed for calibration.
4. Block diagrams showing the various elements included in the system.
5. A mechanical lay out: This could be in the form of diagrams or photographs showing the location of the various elements.
6. Circuit diagrams: These would give details of the electrical circuits of each of the constituent electrical elements of the system and details of each of the electrical components used.
7. Maintenance procedures: This could include preventive maintenance procedures, e.g. oiling procedures, replacement of components after certain times. It also could include a fault location guide and test procedures.
8. Spare parts list.

4.5.5 Maintenance Procedures

Some of the maintenance procedures specific to important measuring parameters are given below:

Pressure measurement

Any pressure measuring system consists of tapping point, isolating valve, impulse lines (signal piping), manipulating valves and the pressure sensor or gauge.

The tapping point and isolating valve may get clogged or choked requiring periodic cleaning. Leaks can also develop in the piping. Chokage and leakage are two important problems to be kept under check for proper measuring of pressure. Inspection and regular cleaning of valves and pipings can be a necessary maintenance requirement.

Pressure measuring instruments with mechanical linkages such as Bourdon gauges can undergo wear and misalignments. Inspection and calibration may reveal such problems. Dirt can affect the operation of linkages. Cleaning and suitable lubrication can ensure that linkages operate smoothly.

Monometers, barometers and vacuum gauges employing mercury can have their measurements significantly affected by dirt contaminating the mercury. A service requirement may thus be periodic inspection of the mercury, and possibly replaced by clean mercury.

Level measurement

Sight glasses may become dirty and make estimation of level difficult. A service requirement is thus likely to be the periodic closure of the arm containing the sight glass so that it can be removed and cleaned.

One of the service requirements for float-operated instruments can be a regular inspection for corrosion of the float and any other parts of the instrument which are in contact with the liquid. Lubrication of moving parts, such as pulley wheels is a must. A periodic inspection of tapes or wires attached to floats is compulsory to check any wear and tear or twist.

Pressure measurement systems used for level measurements need to be inspected as indicated for pressure measurement. There is a particular need to inspect for leaks. With the bubbler method the main need is probably for cleaning of the tube since it can easily be blocked.

Flow measurement

Inspection of leaks in piping, wear at head producers (orifices, venturies etc) and cleaning of deposits of mud, solids etc. behind such items as an orifice plate are likely to be routine service requirements. Manipulating valves or equalizing valves near flow meters/transmitters require a periodic inspection and checking. Pressure measurement systems associated with flow measurement will require the type of servicing suggested above for pressure measurement.

Flow measuring instruments other than that of head producer types will have to be handled as per service requirements mentioned by the suppliers.

Temperature measurement

Instruments employing Bourdon gauges will require the type of servicing indicated for pressure measurement systems. Another requirement may be for calibration checks. This can be done by comparing the responses with those of a standard thermometer.

As a majority of the temperature sensors are of electrical nature, such as thermocouples, RTD, thermistors etc., the cabling from the sensors to the indicators/recorders needs periodic checking. Insulation values between conductors and conductor to earth, short-circuiting or open-circuiting etc. are to be checked as the maintenance activity. Compensating leads connected to thermocouples pose problems many times. They are to be maintained properly.

Analysing instruments

Sampling of the medium is very important here. Chokage proof and leakage proof system is very essential. Conditioning of the sample before allowing it to analysers is also very much essential. Dust catcher, moisture remover, cooler/heater, suction pump etc. connected with analyzing system, pose challenges in maintaining them. Reference gases required for calibration either online or offline need special mention here.

The analyser hardware is likely to receive better care if it is accessible and housed in pleasant surroundings, such as in air-conditioned buildings. Spare parts and testing components should be ordered at the same time as the system to avoid future delays; the availability and most effective use of qualified maintenance personnel are also some of the factors of major importance.

A similar type of analysers already used in the plant are helpful in determining maintenance and spare parts requirements. The major sub-assemblies not stocked as spare parts can also be interchanged and can help to obviate the waiting for parts for the duplicated system.

Location for the analyzer must be selected after considering ambient conditions, availability of utilities, space and read out location, safety, access for maintenance, and analyzer response time.

Analysers may be purchased in one housing or in several modules. A modular approach can often reduce space requirements, provide remote readout, improve safety, provide easy maintenance access, and reduce sample transport time.

Transducers/Transmitters

Transducer or transmitter is an electronic unit which converts various inputs like differential pressure, displacement (linear motion), pressure, mV (thermocouple output), resistance variation (RTD outputs) and other low current/low voltage inputs from many other sensors into a standard load independent 4–20 mADC output. Such transmitters are two-wire systems combining the input power supply and signal output together. Maintenance as well as calibration of such transmitters are very vital in thermal power plants. It is always advisable to follow the service instructions/maintenance manuals provided by the manufacturers. Experience gained by the instrumentation personnel with similar such transmitters already in use will help a lot to fix the frequency of calibration and plan maintenance schedule.

4.6 INTRINSIC AND ELECTRICAL SAFETY

4.6.1 Intrinsic Safety of Instruments

Definition

Intrinsically safe instrument and wiring shall not be capable of releasing sufficient electrical or thermal energy under normal or abnormal conditions to cause ignition of a specific flammable or combustible atmospheric mixture in its most easily ignitable concentration (Abnormal conditions

shall include accidental damage to any field-installed wiring, failure of electrical components, application of over-voltage, adjustment and maintenance operations and other similar conditions).

A quantity of a combustible mixture must be heated to its ignition temperature for an explosion to occur. A weak spark heats so little mixture that heat loss exceeds the heat supply and the incipient explosion dies out. A large spark heats enough mixture for combustion to become self-sustaining and an explosion propagates. If energy is kept at a low level, ignition will not occur. This is the basis of intrinsic safety. It is not sufficient that energy be low in normal operation. It must be also below under any conceivable abnormal operation or fault condition.

Energy levels

Safe energy levels cannot be defined in any simple form. Ignition depends on specific gas, gas concentration, voltage, current, energy storage elements, contact materials, contact size and speed of opening and closing of contacts. Actual ignition testing of the specific apparatus is the preferred practice.

Loop concept

In evaluating instrument for intrinsic safety, it is always necessary to look at all elements of the complete loop. For example, an ordinary thermocouple, by itself, is unquestionably safe. Add a simple millivolt indicator and it is still safe. Connect the thermocouple to a recorder powered from a 220 V line, and the question of safety arises. Something wrong in the recorder might put dangerous energy on the thermocouple leads. The problem can be easily solved by good design and construction in the recorder, but it cannot be overlooked. Someone must evaluate the combination of the loop elements and assume responsibility for safety.

Determining intrinsic safety

The practical answer for the instrument buyer and user is to look for certification by a qualified testing agency. While each testing agency has its own detailed rules and traditions, the following three steps are involved for a reasonably typical evaluation.

1. Circuit analysis—to determine worst possible fault conditions.
2. Evaluation—to insure a margin of safety under the conditions found above.
3. Construction review—to insure that the critical components are reliable and that circuit will function as planned.

1. **Circuit analysis:** It is a review of the circuit, component by component, considering the possible mode to failure of each and its effect on energy levels available in the hazardous area. It starts where line power enters the system and includes all parts of the inter-connected instrument system wherever located in the control room or in the field. The object is to pinpoint the fault condition or combination of conditions allowing highest energy in the field circuits.
2. **Evaluation:** The purpose is to ascertain whether or not each fault condition constitutes a possibility of ignition. With the use of the actual circuit, the faults are produced by short-circuiting or open-circuiting components with the field leads connected to a test apparatus. The test apparatus consists of a pair of contacts operating in a chamber filled with the most readily ignited mixture of a suitable combustible gas with air. The contacts

simulate a broken wire, a wire dragging on a surface, or the short-circuiting of a pair of leads. It is also possible to use measured voltages, currents, inductances, capacitances etc., and compare them with the results of previous tests with similar circuit parameters.

3. **Construction review:** A circuit component must be of a reliable form of construction if it is to be depended upon for safety. A transformer that will withstand a high potential immediately after being deliberately burned out, is considered reliable. This presupposes that the transformer is so constructed that consistent performance of this nature can be anticipated. A resistor must withstand gross overloading without significantly changing in value. Live parts, such as terminals must be so separated that an accidental short-circuit is essentially impossible. If an instrument system survives this kind of examination, its safety is assured.

4.6.2 Electrical Safety

There are three ways in which electricity can kill or injure. Two are indirect—the result of fire and the result of explosion. One is direct-electrocution by electric shock. The danger of electric fire from electric causes is generally confined to the supply side of instrumentation from the point where power enters the system upto and including the power transformer found in most process control instrumentation. Instrument field wiring, employing the popular signal of 4 to 20 mA DC, and lower, operates at energy levels at which fire hazard is remote. Power supply to the point of entry into an instrument is subject to detailed rules and regulations followed by the country. Electrical safety depends primarily on three fundamental factors:

1. Enclosure of live parts, both to avoid personnel contact and to avoid accidental short-circuiting.
2. Fuses or circuit breakers to open in case of overload.
3. Grounding of all exposed metal.

Enclosures

Because instruments differ in use, the usual rules for electrical enclosures need modification when applied to them. NEMA (National Electrical Manufacturers Association) types of enclosures modified for Industrial controls followed in United States of America are used in most of the countries now. A number of various types of enclosures are recommended depending upon the application, location and need. General purpose enclosures, dust proof enclosures, weather proof enclosures, water-tight enclosures, enclosures for hazardous locations, explosion proof enclosures, oil tight enclosures, acid and fume resistant enclosures etc. are some of the standard enclosures available. One has to select the type of enclosure suitable for the particular application in mind.

Fuses and circuit-breakers

Conventional fuses and circuit-breakers are used for protecting group of instruments. Smaller fuses and mini circuit-breakers are used to protect individual instruments. As many instruments draw a.c. supply from the mains and generate their own d.c. stabilized supply, fuses are provided both in a.c. side and in d.c. side. Fuses and circuit-breakers are installed and housed in such a way that no fire hazard is encountered while blowing or tripping.

Grounding

A low resistance, non-current-carrying metallic connection to ground should be established and maintained from every exposed metallic surface that can possibly be connected to an electrical circuit. Grounding is usually accomplished by bonding all elements together in a system terminated at the ground connection where power enters the premises.

Grounding serves two distinct purposes, both relating to safety. First, since ordinary power circuit has one side grounded, a fault that results in electrical contact to the grounded enclosure will pass through current to blow a fuse. Second, possibility of shock hazard is minimized since the low resistance path of a properly bonded and grounded system will maintain all exposed surfaces at substantially ground potential.

Grounding is effective against hazard from leakage currents. A proper grounding system with low electrical resistance will conduct leakage currents to ground without developing significant potential on exposed surfaces.

Grounding of exposed metal surfaces is distinct from the grounded conductor of the ordinary power wiring. The latter is a current-carrying ground, capable of developing significant potential, particularly on long lines, and with surge or even short-circuit currents. The grounding systems are substantially non-current-carrying, except for possible leakage currents. Potential can build up only during the time required for a fuse to blow as a result of a specific fault that results in direct contact between power and grounding systems. Grounding is customarily not required for signal circuits where either the maximum voltage is 30 V, or the maximum current under any circumstance cannot exceed 5 mA.

Personnel safety

The electrical energy necessary to kill or injure a person varies widely with conditions of exposure, especially with contact conditions; i.e. wet or dry skin, contact area, and the path the current takes through the body. A few millivolts applied directly to the heart can cause fibrillation and death. The significant factor is current through the body. A current of less than 1 mA is imperceptible of a normal man. Above 3 mA, it becomes unpleasant. Above 10 mA, the victim is unable to let go. Above 30 mA, asphyxiation may result. Still higher levels lead to heart stoppage and death. These values are for sustained contact. Much higher levels can be tolerated for a fraction of a second. Internal body resistance can be as low as 100 Ω but the resistance of the whole body is primarily in the skin and in skin contact. In dry conditions the resistance of the whole body may be as high as 100,000 Ω. In all eventualities, if all line voltage circuits are enclosed in properly fused and grounded enclosures, and signal circuits not meeting either the 30 V or the 5 mA criteria are guarded, personnel safety will be assured.

4.6.3 Explosion Hazards and Intrinsic Safety

Areas in which combustible gas, vapour, or dust may be present in explosive proportions are called *hazardous locations*. Special precautions must be taken with electrical equipment in hazardous locations to eliminate a source of ignition that could touch off an explosion. The specific precautions vary with the nature of the combustible material and the probability of its presence.

Explosions

An explosion is dependent upon the simultaneous presence of three things:

1. **Oxidizer:** Ordinarily present in the form of oxygen in air.
2. **Fuel:** A gas, vapour or finely divided solid and
3. **Ignition source**.

By definition, a hazardous location is a place where fuel and oxidizer are present in combustible proportions, at least at times. Ignition of this dangerous combination must not be permitted. Electrical equipment must be built and operated in a manner to prevent its becoming a source of ignition. It could ignite this hazardous atmosphere in either of two ways: by surface temperature in excess of the ignition temperature or by sparks. Some sparks are incidental to normal operation, as in the operation of switches; some are accidental, as in faulty connections. Both must be guarded against.

Protection methods

There are several approaches for protection of explosion and to ensure safety.

1. Confine explosions so that they do not damage:
   Explosion proof or flame proof enclosures which are strong enough to withstand internal explosions without damage and tight enough to confine the resulting hot gases so that they will not ignite the external atmosphere are used.
2. Keep atmosphere away from ignition source (Purging, pressurization or ventilation, oil immersion, sealing or bolting).
3. Limit energy to levels incapable of ignition (intrinsic safety).
4. Miscellaneous approaches: Sand filling, increased safety, dust ignition proof and nonincendiary

All methods are safe if the equipment is properly selected, installed and maintained. Cost of instrument, cost of installation, cost of maintenance and flexibility are all to be taken into account before deciding about the protection methods.

4.7 INTERLOCKS FOR BOILER OPERATION

Interlocks are mainly used in boiler operation for the following:

1. Safety of men and machine
2. Start up and shut down of boiler
3. Sequencing of burner and other operations

Operations relating to safety, startup, shut down, and sequencing are basically digital in nature and operate from inputs, such as contact closures. Hence the interlocking operations are generally accomplished by either relays or solid-state hard-wired logic systems. Nowadays, these functions are frequently accomplished by programmable logic controllers (PLCs). In modern power stations, the PLCs are hooked up as a part of distributed control system (DCS).

4.7.1 Safety Interlocks

The basic safety interlocks are listed below:

(a) Fuel admission interlock: Fuel is not supposed to be admitted initially unless the furnace is thoroughly air-purged.

(b) Low air flow: Due to any reason if the air flow goes down below some minimum level, the fuel has to be shut off.

(c) Lower fuel supply: If the quantity of fuel flow is very less or pressure is below the safe level, the fuel has to be shut off to avoid unstable flame or backfire.

(d) Loss of flame: Fuel has to be totally shut off if loss of flame is detected either in the furnace or in the individual burners.

(e) Fan interlock: For normal operation of the boiler both ID and FD fans are to run normally. Stoppage of one may require the stoppage of the other one also.

(f) Low drum level: Low drum level requires the stoppage of fuel. This is normally an optional one.

(g) High combustibles: If the high combustibles are found in the waste gas, it may be required to shut down fuels and check for the reasons. This is also an optional one.

The various interlocks are to be designed properly to operate the equipment safely. It is also required to satisfy the conditions of the regulating authorities.

4.7.2 Start-up and Shutdown Interlocks

Whenever a boiler is taken into range after shutdown or shutdown for maintenance purpose, a proper sequence of operation has to be followed. Such sequential operation during start-up and shutdown are controlled/managed through interlocks.

After the maintenance work is done, a pressure test has to be carried out in presence of boiler inspector, an authorized person from the regulatory body. While carrying the pressure test, feed pump has to be started, the pressure built up to the level of the norm set and sustained for the prescribed period. The timing, alarming when pressure drops prematurely etc are to be hooked up through interlocks.

Before the boiler is taken into range, the safety valve adjustment has to be carried out. The safety valve should be adjusted in such a way that whenever the boiler steam pressure exceeds the set value, the safety valve should operate and vent the steam to atmosphere. This interlock is very essential to safeguard the equipment from getting damaged due to high pressure.

Automatic startup sequencing of feed water circuit, combustion air and furnace draft, lighting the burners and for sequencing them in and out of operation is common. They are accomplished with different sets of contacts generated by switches, relays, instruments or logic systems. Similarly the shutting down functions are also carried out through various interlocks.

4.7.3 Sequencing of Burner and Other Operations

For lighting up burners it is to be ensured that ID fan is running trouble-free and developing required draft, FD fan is running healthy, the pilot burner is burning with required flame length, feed pump is running and the drum water level is normal. All safety interlocks connected with combustion system are to be tested and kept ready also. Fuel and combustion air may be admitted manually first and the burning of all burners ensured before the system is taken into automatic mode. If oil is used, the availability of atomising steam with required pressure is to be ensured. All interlocking contacts are generated through pressure /flow/level switches, contact manometers, contact thermometers, limit switches and built-in indicator contacts.

4.7.4 Programmable Logic Controllers (PLCs)

A PLC is a user-friendly, microprocessor-based specialized computer that carries out control functions of many types and levels of complexity. Its purpose is to monitor process parameters and adjust process operations accordingly. It can be programmed, controlled and operated by a person unskilled in operating computers. Essentially, a PLC operator draws the lines and devices of ladder diagrams with a keyboard onto a display screen. The resulting drawing is converted into computer machine language and run as a user program.

The computer takes the place of much of the external wiring required for control of a process. The PLC can operate any system that has output devices that go 'on' and 'off', known as *digital outputs*. It can also operate any system with variable (analog) outputs. The PLC can be operated on the input side by 'on' and 'off' devices or by variable input devices.

Advantages of PLC

1. **Flexibility:** It is possible to use just one model of a PLC to run any one of 10 (assume no of machines $n = 10$) machines instead of using 10 different controllers for 10 machines.
2. **Implementing changes and correcting errors:** When a PLC program circuit is designed, the PLC program can be changed from a keyboard sequence easily. Also if a programming error has to be corrected in a PLC control ladder diagram, a change can be typed quickly.
3. **Large quantities of contacts:** A PLC can have a large number of contacts for each coil available in its programming.
4. **Pilot running:** A PLC programmed-circuit can be prerun and evaluated in the office or laboratory. The program can be typed, tested, observed and modified if needed, saving valuable factory time.
5. **Visual observation:** A PLC circuit operation can be seen during operation directly on a CRT screen. The operation or misoperation of a circuit can be observed as it happens.
6. **Speed of operation:** The speed for the PLC logic operation is determined by scan time, which is a matter of milliseconds.
7. **Ladder programming method:** A PLC programming can be accomplished in the ladder mode and a PLC programmer who works in digital/Boolean control systems can easily perform the PLC programming.
8. **Reliability and maintainability:** The PLC systems are more reliable to operate and require less maintenance.
9. **Security:** A program change cannot be made unless the PLC is properly unlocked and programmed.
10. **Fail-safe operation:** In relay systems, the stop button electrically disconnects the circuit. If the power fails, the system stops. Furthermore, the relay system does not automatically restart when power is restored. In PLC, this drawback can be overcome by adding safety relays to a PLC system.

Overall PLC system

Figure 4.4 shows a simplified PLC system with input modules, output modules, microprocessors, memory etc. Input modules accept the inputs in the form of contacts or digital inputs, in 'on' and

'off' fashion. The functional requirement with the inputs is configured/programmed in the PLC so that it outputs the required signal only when the conditions are satisfied.

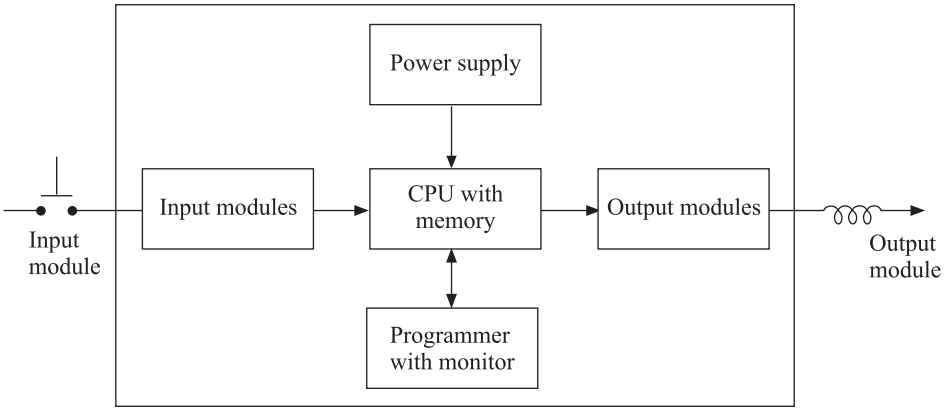


Figure 4.4 Overall PLC schematic.

To understand the working of a PLC, the ladder diagram for a standard start-stop seal circuit is shown in Figure 4.5 and a forward-reverse control is shown in Figure 4.6.

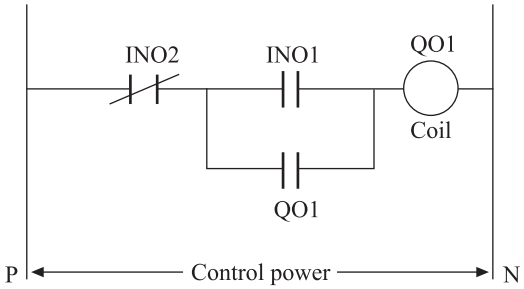


Figure 4.5 Standard start-stop circuit.

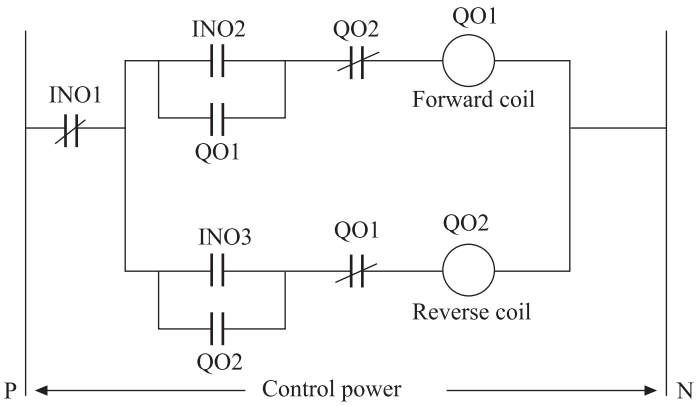


Figure 4.6 Forward-reverse control.

Standard start-stop circuit: Let us take an example of starting a feed pump through PLC and stopping it whenever required. Whenever the coil (QO1) is energized, the feed pump motor will get supply and start running. When QO1 is de-energised the pump will stop. In between start and stop signal, it should continue to run. It is explained below how the above task is accomplished by PLC. INO1 is the start switch whose contact remains normally open and closes only when it is pressed. INO2 is the stop switch whose contact is normally closed and opens when it is pressed. QO1 is the coil whose main contacts are used for supplying power to feed pump when energized. The contact QO1 is a normally open contact and closes when the coil is energized and remains in that condition as long as QO1 is in energized condition.

When INO1 is pressed to start the feed pump, QO1 gets supply through INO1 and INO2 and energizes. The sealing contact, also called as self-holding contact, closes and keeps the QO1 in energized condition even after INO1 is released. The feed pump starts and continues to run. For stopping the pump, stop switch INO2 is pressed to break the contact. Then QO1 de-energizes and hence the contact QO1 opens. Feed pump remains in stop condition even after INO2 is released. Also, if the control power goes off, QO1 de-energizes and stops the pump.

Interlocking circuit: A simple application of operating a control motor can be taken up to understand the interlocking concept. The motor can be operated either in forward direction or in reverse direction. The motor should never get power to run in both directions at the same time. This has been explained in Figure 4.6.

The forward coil QO1 can be energized with start button INO2 and the reverse coil by INO3. The single stop button INO1 will de-energize both. Interlocks are provided through QO1 contact in QO2 circuit and QO2 contact in QO1 circuit so that both cannot be energized at the same time. The main purpose of interlocking is to provide safe operation without failure.

4.8 COMPUTER BASED CONTROL AND DATA LOGGING SYSTEMS

4.8.1 Introduction

The advent of microprocessor and microcomputers has changed the field of process control that too power plant control, completely. The tasks performed by single-loop controllers which were wired to mini-process computers (analog computers initially) are now easily programmed using microcomputers. In the past, computers were used only to supervise the analog controllers which were interfaced to the process directly. One such supervisory computer control system is shown in Figure 4.7.

Sensors and transmitters measure the required parameters of the process. The output signals of such devices are received by analog controllers. The controllers develop signals as per set points and actuals which are utilized to operate final control elements to bring the controlled variables to the set-point levels. The status of analog controllers are provided to supervisory control computer so that the supervisor can have an overview of the whole process. The set points can be generated either by the operator or by the process model embedded in the controller. The set points can be set manually also in the controllers directly.

The microprocessors and microcomputers, emerged in the market later on, made the analog computers outdated. These digital units have become more efficient and cost-effective. They are

used not only for control functions but also for engineering, design, financial and plant management functions. The digital computers thus developed are used for data-logging and supervisory control applications.

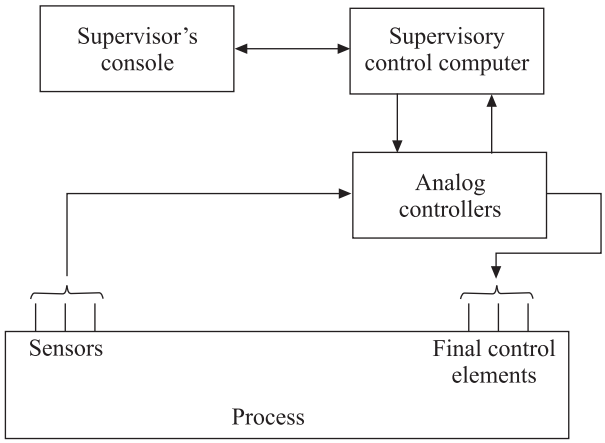


Figure 4.7 Supervisory computer control.

4.8.2 Data Logging (Data Acquisition System)

The operation of power plant always involves a lot of data like production rates, raw materials cost and efficiencies of control in addition to other operating parameters. Some are fed manually, but most others are continuously measured and transmitted. Some of the data are generated from the information collected. Digital computers with mass storage capacity enable data-logging function to be performed easily. It is also possible to record such data continuously. Performing different calculations to arrive at various efficiencies, technical factors and cost analysis are possible. The basic schematic of a data logging/data acquisition system is shown in Figure 4.8.

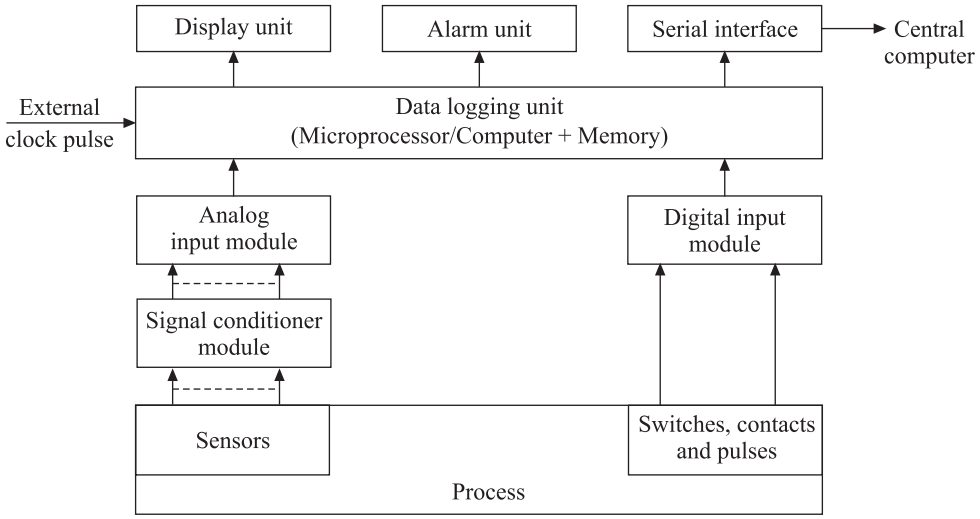


Figure 4.8 Basic data acquisition system.

4.8.3 Supervisory Control and Data Acquisition System

The computer-based data-logging/data-acquisition system can be extended to give computer feedback on the process through automatic adjustment of loop set points. In other words the set points for the control loops can be generated and altered through a supervisory computer. Since the choice of set point is a function of many other parameters, it can be automatically adjusted by having an embedded model developed by experienced experts of power plant operation. Since a number of loops is involved and a decision to alter one set point may necessitate the alteration to set points of many other loops as there will be interactive effects. Considering the number of loops involved, interactions and calculations required to take decisions, it is better to let a computer perform these operations. A system combining both data acquisition and supervisory control has come into existence for power plants. Such a system is called in short SCADA (supervisory control and data acquisitions). To perform the above function in addition to data acquisition, data-output system (DOS) is added.

Figure 4.9 shows such a system interconnecting all necessary components. Please note that for proper understanding, only four control loops are shown. In the same fashion all other control loops in a boiler or power station can be hooked up.

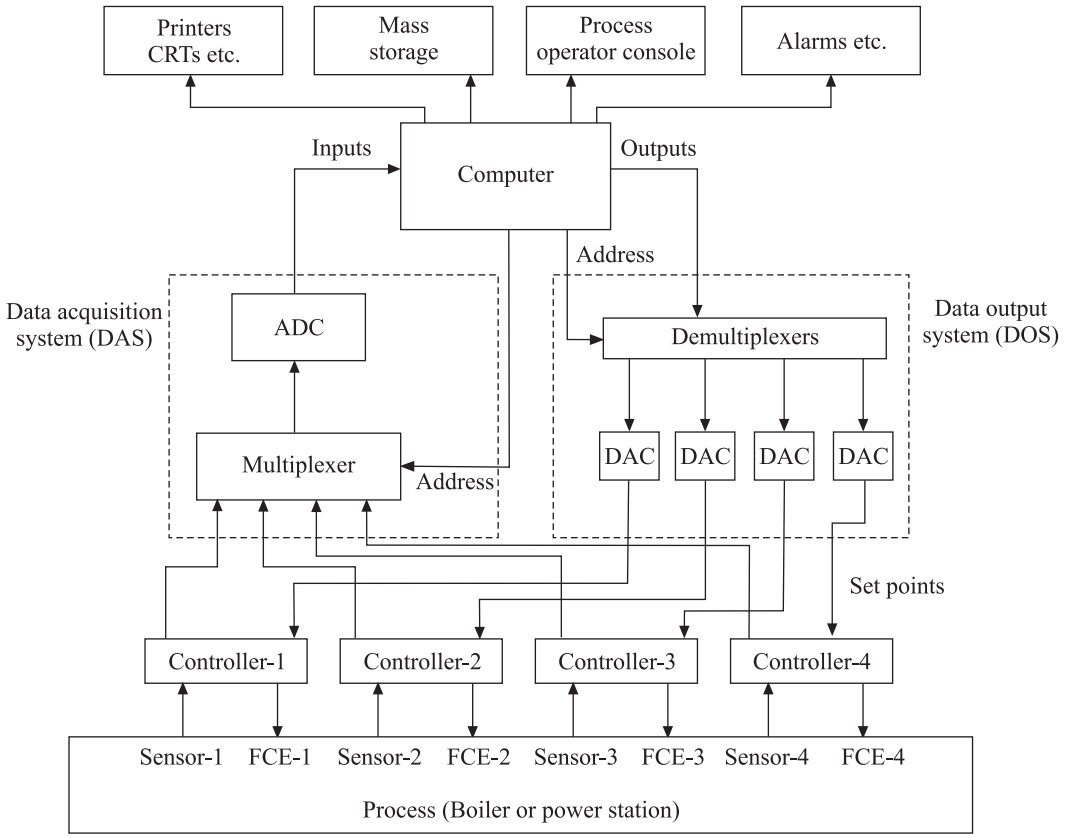


Figure 4.9 Supervisory control and data-acquisition system (SCADA).

4.8.4 Control System Networks

Process control and control systems basically started with pneumatic measurements and controls with 0.1 to 1 kg/cm^2 (5 to 15 psi) as standard signal. The media used for communication is air (called *in process control language as instrumentation air*). Air is used as medium of communication mainly because of safety reasons. To avoid power-carrying cables in hazardous and accident-prone areas of petrochemical and chemical industries the air media was used. As time passed on, electronic sensors and instrumentation were introduced to avoid overvoltage entering the prohibited zone causing sparks and hence accidents. When electronics ruled the roast, number of standards like 0–50 mA, 0–100 mA, 0–250 mA, 0–10 V, 0–20 V etc. were followed by different companies. Then came the universally accepted 4 to 20 mA (or 1 to 5 V) as the standard signal for process control instrumentation. This again required a lot of long cables running between field (plant) and centralized control room as because for every parameter one cable for carrying signal from field to controller and another pair of wires from controller to the final control element had to run. During this time analog controllers were used mostly.

There have been two major revolutions in the field of process control in the last 20 years. The first was the replacement of analog controllers by digital controllers using embedded computers to perform the control function. We have already studied this technology and showed how controller action is accomplished by software in the computer. Even we have gone up to digital data acquisition system and supervisory control of plant parameters in the previous sections.

The second revolution, which is happening even now, is replacement of the standard 4–20 mA analog signals for communication throughout a process plant by serial digital communication via a network. For control system data communication, we call the serial communication system a 'fieldbus' because of the kind of network it employs. In this section, the basic features of fieldbus serial communication systems will be presented.

Process control networks

When the first revolution was taking place in the process control field, systems were developed to allow computers to communicate serially over a pair of wires in the computer industry. In this case, the data expressed in binary was sent serially as a stream of 1's and 0's from one computer to another. As the technology of serial communication matured, methods were developed to allow several computers to use a single pair of wires by sharing time slots on the wires so that one pair of computers is communicated and then another pair, and so on, but so fast that it seemed that all computers were communicating at once over a single pair of wires. This kind of multiple-user communication required development of protocols about how a computer could gain access to time on the line for communication and how computers could be identified so that communication could be between specific computers. This eventually gave rise to a myriad of open standard technologies including the Ethernet, local-area networks (LANs), TCP/IP addressing and transmission protocols, wide-area networks (WANs), and of course the World Wide Web (WWW) as a super network. The use of open standards for protocols and communication allows many manufacturers to design and market equipment and software to further develop this networking technology.

In the supervisory control (Section 4.8.3), process signals were predominantly carried by analog 4 to 20 mA current. The operations of controller computers were managed over a serial

network, including changing set points, modes of controller action, and gains. Eventually there was a move, in the second revolution, to eliminate 4 to 20 mA data communication standard and let actual process data be carried from sensors to controllers and controllers to final control elements via digital serial networks.

Figure 4.10 shows the various configurations of the networks, such as stars, rings, and a bus. The 'bus' uses straight runs of parallel wires with devices simply connected in parallel across the wires. Traditionally in a manufacturing facility the plant outside the control room is referred to as a field, so we have a 'fieldbus'. Many types of fieldbuses were put forward by process equipment manufacturers, many of which are not open. Finally, several open systems were developed and, at the present time, there is competition between these standards for adoption by the process industries. The advantage of an open standard is that a process plant or manufacturing facility can buy equipment (sensors, actuators, controllers etc.) from a variety of manufacturers and connect them all together seamlessly on the network. Figure 4.11 shows how the serial fieldbus connects field hardware to computers.

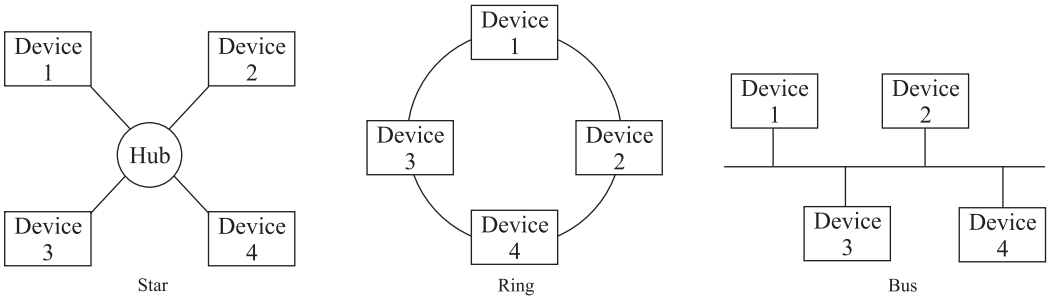


Figure 4.10 Configurations of networks.

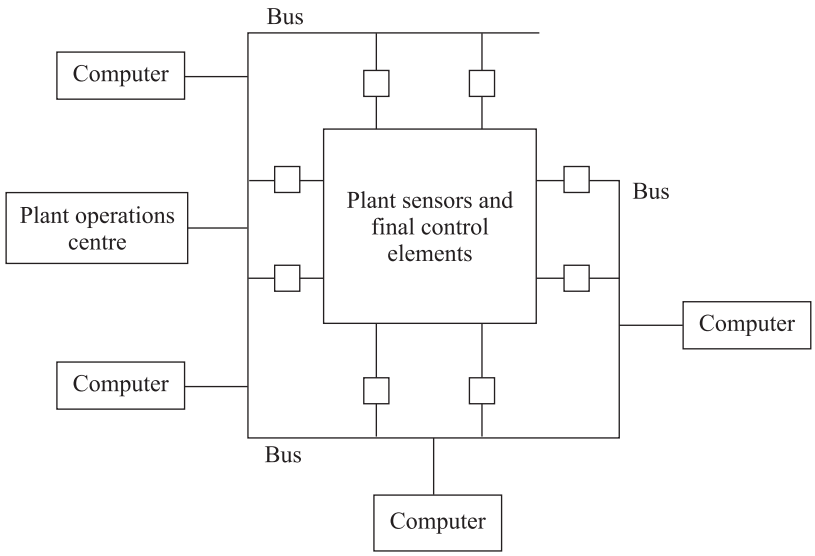


Figure 4.11 Connection of serial fieldbus to field hardware and computers.

Field bus operations

To understand about fieldbus operations, we may consider a process (heating liquid in a tank) as example. Among many other parameters, we consider two specific parameter loops as shown in Figure 4.12. First loop consists of a level sensor, computer and a final control element to adjust the liquid flow as per computer output. The second loop consists of a temperature sensor, computer and a control circuit with heater. Every device will have a unique network address. Each device also has the basic intelligence to communicate over the serial bus. The control process might go as follows, with all communication over the serial bus as digital bit streams:

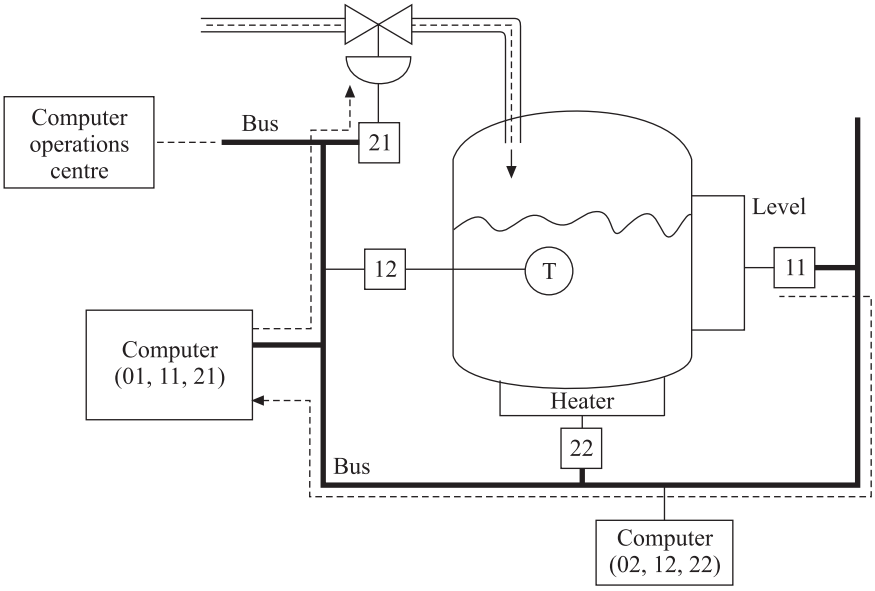


Figure 4.12 Fieldbus operations.

1. Computer 01 sends a request to level sensor 11 asking for the actual value reading. To do this the computer forms a packet with its address (01), the sensor's address (11) and a code to request a reading.
2. The level sensor sends level data back to computer. The level sensor must have the intelligence to form a packet with the computer address, its address and the digitally encoded level.
3. After solving the control equations, computer 01 sends a valve-setting signal to valve 21. To do this the computer forms a packet with its address, the valve address (21), and a digitally encoded valve setting.
4. Valve 21 drives the valve to the new setting and, in some cases, may send an acknowledgement back to computer 01.

The cycle continues and the level is maintained at the required set point.

A similar measurement, evaluation, and feedback process may be going on at virtually the same time with the temperature control system with the help of computer (02), sensor (12), and the final control element (heater) (22). Because of their unique addresses, the two loops will concentrate on their own communications ignoring others. By sharing time on the serial line at

very high speeds the two loops seem to use the bus at the same time. Meanwhile the operations central computer can also be requesting readings from the sensors to monitor the plant operations. The operations central computer can also request reports from the control computers. One of the big advantages of this system is that the large numbers of wire-pairs necessary for the 4–20 mA current communication are eliminated.

Fieldbus characteristics

Fieldbuses used in power plants vary with the manufacturer of the system. They will have their own features. Some common characteristics like addresses, data packets, media, speed, cycle time, interoperability, etc. can be used to compare the buses. All buses carry serial digital data. The bus wire carries a time series of pulses representing ones and zeros.

For identifying the device connected to the bus, an addressing protocol is employed. Depending on the number of devices connected to the bus, the number of bits allotted to the address may vary. A data packet normally will contain the data, the address of the sender and the address of the receiver. The medium that carries data include twisted copper wire pair, coaxial cable, fibre-optic cable, and wireless radio frequency propagation. The data propagation speed across the network is typically given as number of bits per second (bps). The time required for a data update to propagate through the system is called *cycle time*. The number of devices connected to the bus and the speed of the bus determine the cycle time. Interoperability is another important feature which decides how easily the computer and devices can be added to the bus.

Fieldbus types

There are many types of fieldbuses in operation. Foundation field-bus and Profibus (Process fieldbus) are the two most commonly used ones.

OSI 7 – Layer protocol: The way by which the bus system packages are transmitted is called *protocol of the fieldbus*. The International Organization for Standards (ISO) has defined a reference model for communication between open systems which is called 'Open Systems Interconnection' or in short OSI model. This model applies to almost all communication systems. Since 7 functional layers are involved in this protocol, it is also called OSI – 7 layer protocol. The 7 functional layers are shown in Figure 4.13. Generally only three layers, namely physical layer, data link layer and application layer are used in the power plant applications. Those three layers only are discussed here briefly.

Layer 7	Application layer
Layer 6	Presentation layer
Layer 5	Session layer
Layer 4	Transport layer
Layer 3	Network layer
Layer 2	Data link layer
Layer 1	Physical layer

Figure 4.13 OSI-7 layer model architecture.

1. ***Physical layer:*** Physical transportation of data from device to device is defined here. Specification of electrical signals, cabling, topology and transfer speed are included. Cables used are twisted pair of copper wires, coaxial cable and fibre-optic cable. The

transmission rates vary from 32 Kbps for twisted pair copper wires to 10 Mbps for coaxial cable and to a few Gbps for fibre-optic cables.

2. ***Data link layer:*** Data link layer is meant for exchange of data between devices. It governs the mechanism for ensuring data security. As many devices are connected to the bus, there should exist definite rules for allowing which one to communicate at any point of time. Central and de-central methods of regulating access are available. A fixed master controls the right in central bus control. The problem here is that the entire network breaks down when the master fails. The de-centralised bus control with flying masters is preferred. Carrier Sense Multiple Access with Collision Detection model (CSMA/CD), Ethernet model (as per IEEE 802.3) and token passing model (as per IEEE 802.2) are the widely accepted de-centralised models.
3. ***Application layer:*** The services supported by the network are defined in the application layer. Read and write commands, program management, up-and-down loading of data, and virtual device images are some of the services covered. For programming the network, the user interfaces with this layer.

   All other layers deal with how the actual data is packaged with control information such as the address of the sender, address of the receiver, size of the data, error correction etc.

Fieldbus category: There are three categories of communication buses based on how much data the system must carry.

1. ***Sensor or bit level:*** Here a single bit is used as primary information carrier. Switches, contacts, limit switches, etc with on/off conditions provide inputs. Outputs would also be similar to inputs to switch on lights, solenoid valves, quick-acting valves etc. These types of bus are used along with PLC installations.
2. ***Device or byte level:*** Here one to several bytes (8 bits) are the primary information carriers. Digitally encoded analog data are sent by using this system. In other words, this type of bus is used when the state of some device requires more than one bit.
3. ***Fieldbus or message level:*** When information with hundreds of bits and thousands of bits combined with encapsulation is to be handled, fieldbus system is used. This system has to take care of complex addresses, error checking and correction as well. This fieldbus is more suited for operating control loops over the bus and for handling large amounts of data. But data rates are slower compared to other two buses because of the large packet size.

Important features of a fieldbus: Signals communication among sensors, controllers and final control elements is done using a fieldbus in power plants. Some of the important characteristics of such a bus are briefed below.

1. ***Physical media transmission:*** With reference to Layer-1 of the OSI model, the actual communication carrier, such as twisted copper wire pairs, coaxial cable and fibre-optic cable are defined by this feature.
2. ***Number of devices:*** The limit to the number of devices that can be addressed
3. ***Distance over which the bus can extend:*** As the distance increases, the distortion to the signals increase. The distance over which the signals can be transmitted without loss of information is another factor to be kept in mind. Special repeater circuits may have to be added to extend the distance.

4. ***Speed of transmission:*** It is expressed in the number of bits per second (bps) that the system can handle.
5. ***Bus powered:*** This feature is regarding carrying of DC current along with communication signals to power the devices.

Comparison of fieldbuses: Table 4.4 shows some of the fieldbuses in use in power plant for comparison purposes.

Table 4.4 Comparison of fieldbuses.

Name of the bus	Category	Physical media	Number of devices	Distance	Speed	Power from bus
Profibus-DP	Fieldbus	1. Twisted pair 2. Fiber optics	127 nodes	1.100 m 2.2.4 km	50 Kbps	No
Foundation-H1	Fieldbus	1. Twisted pair 2. Fibre optics	240/segment 65 K segments	1900 m	31.25 Kbps	Yes
Foundation-HSE	Fieldbus	1. Twisted pair 2. Fibre optics	Unlimited	1.100 m 2. 2 km	100 Mbps	No
Industrial ethernet	Fieldbus	1. Twisted pair 2. Coaxial 3. Fibre optics	Unlimited with routers	1.100 m 2.500 m 3.2.5 km	50 Kbps 10 Mbps 100 Mbps	No
Device net	Device bus	Twisted pair	64	500 m	125 Kbps	No
ASI	Sensor	Twisted pair	31	100 m	150 Kbps	Yes
CAN	Sensor	Twisted pair	127 nodes	25 m to 1 km	10 Kbps to 1 Mbps	No

4.9 DISTRIBUTED CONTROL SYSTEM (DCS)

The direct digital control (DDC) came into picture for thermal power plant operation sidelining analog control system due to the following advantages:

1. Easy configuration, re-configuration and parameterization of control loops
2. Easy self-tuning of controller parameters
3. Simple introduction of new control loops
4. Possibility of realization of advanced control algorithms
5. Model-based optimization of optimal set point values
6. Comprehensive data acquisition and presentation

Though DDC took care of many things required for power plant control, realization of logic and sequential control functions were missing. Operations like start-up and shutdown of boilers were traditionally automated using relay systems, which are separate from control systems. These systems executed both logic and sequential control. Hence the overall systems became expensive and the reliability suffered. To overcome these problems, programmable logic controllers (PLCs) are introduced. They took care in addition to logic and sequence control functions, the functions of timers, counters, registers, etc., besides diagnostic features.

The operator communication through graphic CRT terminals was improved so that the operator was able to use the familiar 'ladder diagrams' for programming of sequential control on the new programmable controllers. Also using modern data communication links, programmable controllers could be easily integrated into complex automation systems.

Then came the distributed control system (DCS) combining the functions of both direct digital control (DDC) and programmable logic controllers (PLCs). Applications showed that in many cases it was advantageous to have both (control functions taken care of by DDC and logic and sequencing functions taken care of by PLC) in the same system (DCS). In DCS, it is distributed functionwise but centralized for supervision. DCS provides the following advantages:

1. Improved plant efficiency
2. Enhanced quality of steam
3. Better safety and reliability
4. Reduced cost and hence improved profitability
5. Greater flexibility of operation
6. Increased visibility into the process.

Distributed control systems have been widely accepted both in power plants and process industries.

4.9.1 Thermal Power Plant Process

The power generation consists of several independent processes such as combustion, water-steam, electricity generation, cooling etc. Power plant operation is essentially a coordination of these sub-processes; each of these independent processes is divided in terms of functions, such as feed water, coal mills, fans, etc. Each sub-process involving several plant equipment is controlled as a group to perform a specific function. It is thus seen that the plant process is divided on the basis of plant-oriented functions. The schematic of the thermal power plant process is shown in Figure 4.14 and the general structure of a thermal power plant is shown in Figure 4.15.

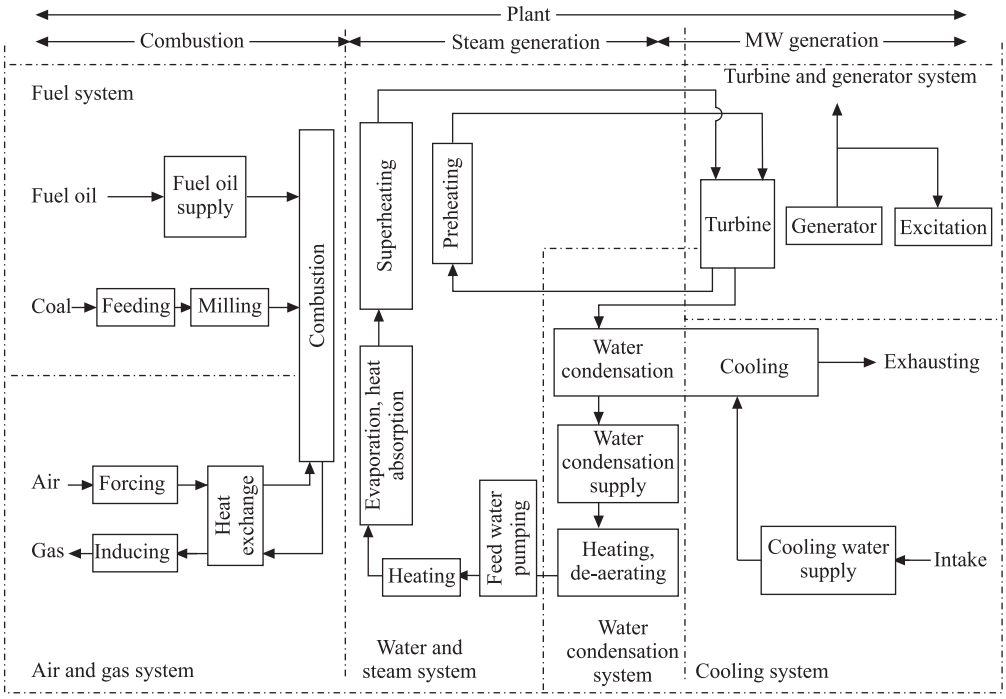


Figure 4.14 Thermal power plant process.

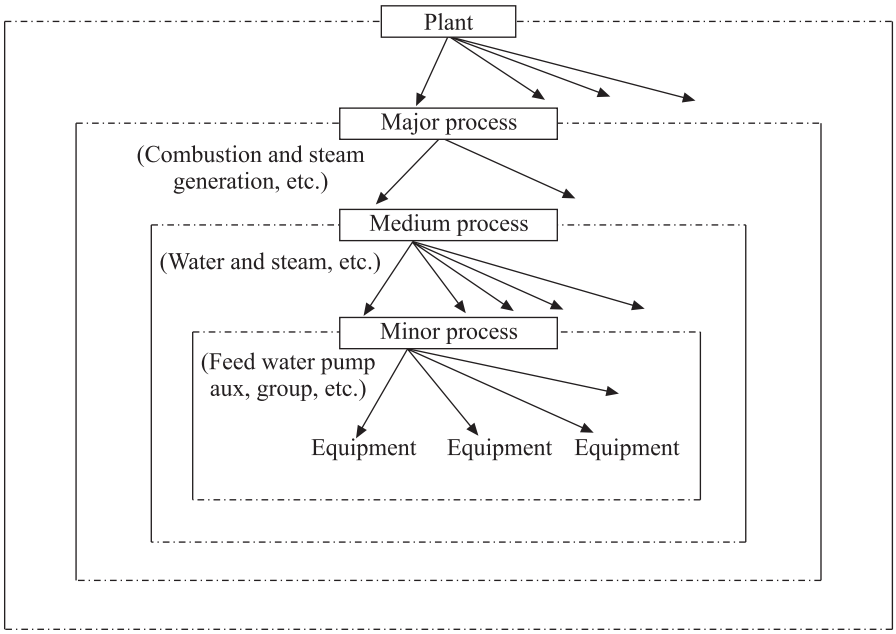


Figure 4.15 General structure of a thermal power plant.

4.9.2 Application of DCS in Power Plants

As seen above, power generation comprises several major processes and each process can be further divided into sub-processes, corresponding to individual pieces of plant equipment. Thus, the DCS architecture for power plant should match this process structure and provide for integrated monitoring, control, automation, and functions, such as boiler automatic control, burner management, turbine control, sequential control and protection and interlock logics. Also, unit level automation and functions for plant monitoring, supervision and maintenance should be included. The application of DCS should finally yield higher operating efficiency and availability of the power plant itself.

The automation structure, based on hierarchical plant process oriented control, is shown in Figure 4.16. The drive controller performs the basic logic, driving, and protection function of single drive such as pump, valve, or damper, whereas the Sub-group controller performs modulating and binary control functions for a sub-process. For example, a sub-group controller for a feed water sub-process controls all the feed pumps that comprise this sub-process. The sub-group controller acts on the drive controllers. A unit master controller (UMC) coordinates the total plant control and gives commands and instructions to the lower levels. It essentially controls plant start-up and shutdown, and coordinates the plant processes during the load variation. At the unit level, computers are used to collect all relevant power plant data, report alarms, and log data, to provide historical storage, performance calculation, plant operation scheduling, high level computer control functions, and man-machine functions. The entire system is interconnected by a hierarchical bus system. A typical structure for such a DCS in power plant automation is shown in Figure 4.17.

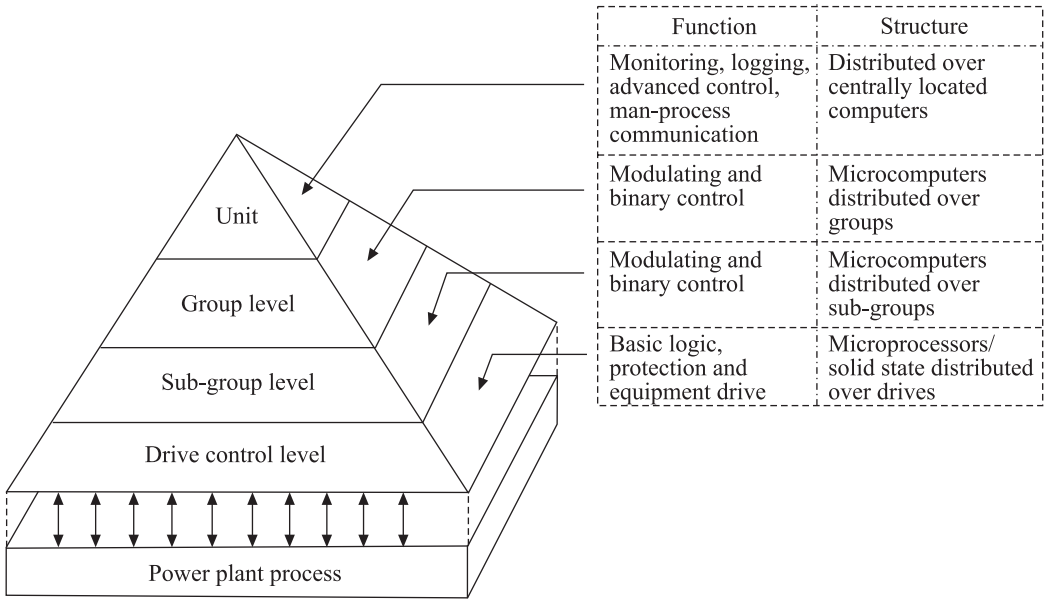


Figure 4.16 Automation structure for power plant control.

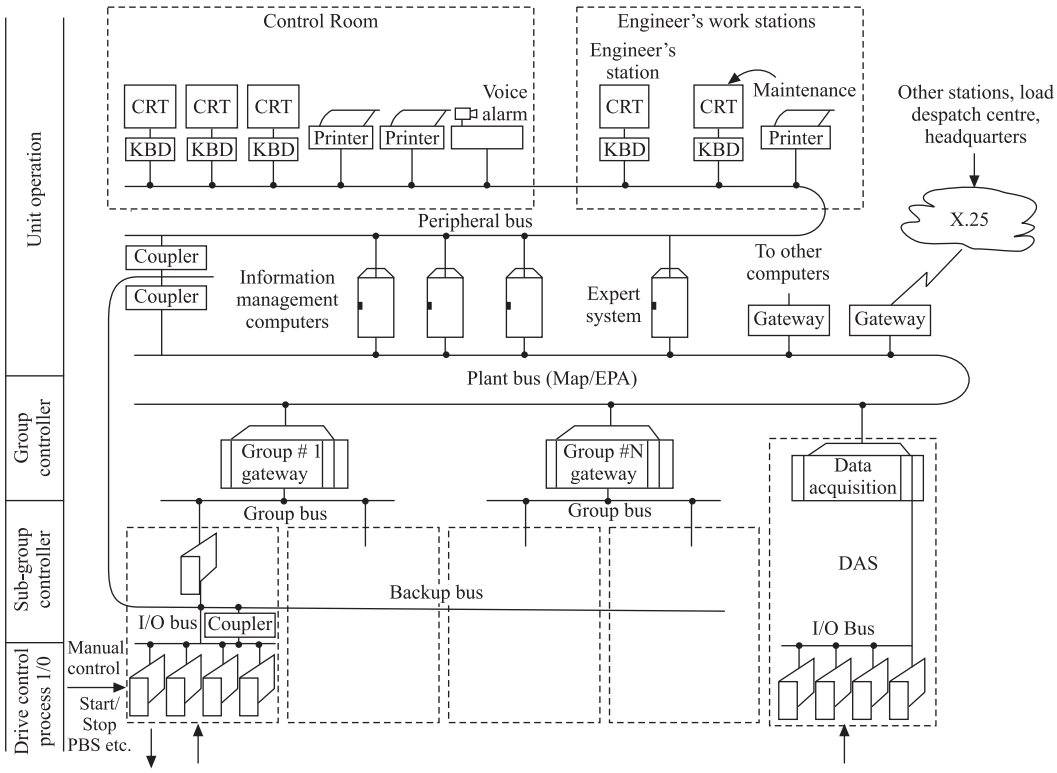


Figure 4.17 Modern DCS for power plant automation.

Hardware system: The hardware of DCS for power plant typically consists of the following:

- Field station
- Sub-group control stations
- Group control stations
- Unit level control stations
- Manual control stations
- Diagnostic station

Field station consists of I/O and drive control modules. These modules provide the interface of the system of the process, including push buttons, indicators, drives, etc. Typically, these modules are characterized by the following features:

Built-in microprocessors-based intelligence in all modules, signal conditioning performed within the module, built-in basic protection using EPLDs, programmable fail-safe output conditions, direct manual intervention at drive levels, plug-in interface for serial I/O bus for greater reliability, serial I/O bus connection to unit level through back-up bus, modulating and binary control performed under control of sub-group controller.

In order to ensure safety of plant equipment, protection logic is included in the drive control modules. This logic could be implemented by *erasable programmable logic devices* (EPLDs), independent of the drive control microprocessor. EPLDs permit customization of logic requirements of each drive.

In the case of binary drives, the facility for manual intervention through manual push-button stations, even in the case of the drive card microprocessor failure, is possible. The *field station c*an incorporate a whole range of I/O cards, supplementing the drive cards, providing intelligent data acquisition and plant monitoring facility.

Sub-group controller station typically comprises a high-performance microcomputer module with direct interface to the serial I/O bus and the higher-level group bus. The sub-group controller contains the control functions and operates directly on the I/O and drive control modules.

Group controller station is provided for the control of each plant sub-process, and coordinates the control of individual equipment group. Group controllers are interconnected via the plant bus and can exchange data among themselves and with the high-level controllers. The group controller is equipped with a high performance microprocessors and the necessary memory modules.

Unit-level control station comprises basically colour CRTs and keyboards, supported by hard copy units. A host of plant data has to be evaluated, sorted, further processed and assigned to the various CRTs for display or printers for logging or simply archived for future retrieval. Similarly, the commands from the keyboard are to be properly interpreted and processed into actions for the controllers. This information processing and management is done in unit level computers, that perform:

- Plant automation and control operation
- Alarm and display control
- Calculations/logs/historical recording
- Software development and database management

The colour CRTs themselves can be implemented as part of low-cost personal computers with the necessary display functions resident in them. All dynamic data required are sent from the unit level computers (ULC). This reduces the processing overhead on this level. The number of

CRT workstations will again depend on the central station philosophy to be employed for a particular plant. The number of unit level computers will also depend on the extent of functions required to be performed.

Manual control station is provided in the field to facilitate the operation of final control elements bypassing all the above control stations. Such an operation is required to be check the condition of control values and for adjustment in the field.

Diagnostic station, normally located in the engineers cabin, provides assistance for on line fault finding and rectification.

The bus system: The I/O bus within hierarchically organized bus system for the DCS architecture of power plant is usually at the lowest level and connects the I/O and drive cards of a particular sub-group. This is a short distance bus, generally confined within the cabinet, which houses a sub-group controller. The I/O bus is controlled by the sub-group controller. Being the lowest level bus, it should have a short time response to plant conditions. However, since the I/O modules are intelligent, only status changes or other significant changes need to be reported over the bus. This reduces bus speed considerations. An RS 485 type of connection is frequently used.

The group bus connects all sub-group controller stations and the pertaining group controller station. The bus enables the group controller to perform the overall control coordination for a group; bus is controlled by the group controller.

The plant bus runs throughout the power plant and connects all group control stations and unit level stations. Typically, the plant bus would be a map-type system, which in future shall integrate other computers and systems. The plant database, which is maintained at the unit level, is updated by the plant bus through the lower level buses. The unit operation commands from the unit master are transmitted to the lower level controller through this bus.

The peripheral bus connects all the CRTs, keyboards, printers, and video copiers, required for the operation and monitoring of the plant.

The back-up bus has been introduced to provide direct connection from the I/O bus to the plant bus so that the CRT/keyboard of the plant operates even in the case of failure at the group and sub-group levels.

In future, when intelligent sensors and actuators are introduced, the need for the many of the I/O and drive cards can be dispensed with. It would then be necessary to link these devices with a *fieldbus.*

Software system: The software system of the DCS includes a wide range of functions to meet the power plant requirements. Typically, the following functions are covered:

Data acquisition and alarming: The system has the capability to acquire the process signals of various scan rates, to perform input conditioning and calculations on inputs, or on groups of inputs, and also to generate calculated variables. Alarms on inputs or calculated variables can be generated on fixed or variable limits, with provision for alarm suppression schemes.

Data logging: A provision is made for assigning of a number of printers at the unit level for logging functions. It is also possible to select any printer for any type of log that can be initiated on demand times. The logs of importance are:

1. ***Periodic logs*** (hourly, daily, monthly, or predetermined time interval like for turbine run-up or boiler start-up).

2. ***Event logs*** (alarms, sequence of events, operator actions, hardware faults)
3. ***Demand logs*** (operator requested log printout like shutdown/trip analysis logs, maintenance logs, performance logs).

The logs and formats are configurable.

Performance calculations: The high-level programming language capability in the system will enable easy performance calculations of units of their monitoring. Such calculations can even be initiated on each cycle scan or periodically, based on averaged or recorded data.

***Control functions*:** The control functions are distributed to the various controllers of the DCS, so that each controller can contain the functions configured from the unit level out of a set of standard algorithms, included in a standard library of program modules. In addition, advanced control algorithms can be provided, some of which are described later.

The unit level computers (ULCs) supervise the plant status and send target values to the lower level controllers, based on which they autonomously operate. During the start-up and shutdown, the operations are under the control of unit level computer (ULC), which will trigger the various sequences to be executed by the lower levels.

Human interface: The DCS provides for man-machine communication, which are CRT-based, and include the features like keyboards and other interactive accessories (light pens, etc.) for operating the plant. Some of the features of the human interface system are:

Alarm display: The features of alarm display are:

- Easy to understand group display of alarm occurrences in chronological order.
- Scrolling of the display as new alarms come on
- Color change and flashing sequences to indicate alarm status.

Mimic display: The features of mimic display are:

- Display of a mimic diagram from a predefined library.
- Zoom into a detailed mimic diagram from an overview mimic display a target mimic (e.g. point details, emergency details, etc).
- Plant control from mimic display.

Trend display: The features of trend display are:

- Eight point trend curve display
- Detailed information on trended parameters
- Exact value/status readout through cursor positioning on curves
- Real time or historical trend display

Bar chart display: The features of bar chart display are:

- Vertical bars representing values of variables
- Alarm limit indication on bar
- Colour changes of bar on alarm
- Operating parameters displayed alongside bars
- CRT/keyboard operation from bar chart display

Operator guidance messages: The feature of operator guidance messages is:

- Special operator guidance display

Multiformat displays: The features of multiformat display are:

- Superimposition of mimics, trends and bar charts
- Window displays

Plant automation messages: The features of plant automation messages are:

- Missing criteria display
- Step execution description
- Break point messages.

Voice alarm annunciation: In addition to alarm reporting through CRTs and printouts, the system will provide audio alarm annunciation through a synthesized alarm message which can repeatedly output through a loud-speaker till acknowledged. The advantages of the voice output alarm are:

- Fast operator response to alarm
- More number of plant people are aware of the alarm.
- Simultaneously the alarm message, depending on priority, can be directed to various levels of plant personnel situated in various areas of the plant.
- The voice alarms can be synthesized in local languages, if necessary.

System reliability and availability

An important aspect of DCS application in power plant is system reliability enhancement through redundancy. The hierarchical system, based on process-oriented distribution proposed above, lends itself for fault tolerance through mutual back-up and redundancies. It provides vital functions to continue system control even with sub-system failures, as detailed below:

Normal operation: Sub-group controllers are coordinated by the group controller. Sub-group is independently controlled by respective distributed controllers. Manual operation is possible through direct push-button intervention at drive control level.

Group controller failure: Sub-group controller continues to operate with normal feedback control function. Degraded functions of group controller can be assigned to Sub-group controller. CRT man-machine operations are possible through the back-up bus which acts directly on the I/Os, or operation can be continued through push buttons and indicators, connected to the drive level.

Sub-group controller failure: Outputs are frozen, feedback control is lost and manual operation is possible from push buttons and indicators or through CRT keyboard through back-up bus. Protection logic is still effective.

Unit level failure: Unit Level functions are degraded and assumed by the group controller. Sub-group control is still maintained by respective sub-group controller, and the man-machine communication retained.

In order to provide fault tolerance without degradation in function, redundancies have to be built-in. As a rule, all power supplies and communication links are duplicated. The CPUs at the sub-group and group control levels are duplicated, so that the redundant CPU in 'hot standby' mode directs operations in the event of failure of the main CPU. At the unit level, No:1 back-up is implemented. Functions of the failed processor are automatically taken over by the standby processor, which is common for a number of processors. The assumption here is that only one processor will fail at a time. Thus, a totally redundant hierarchical system can be realized.

4.9.3 Advanced Control Algorithms

Application of DCS can directly implement advanced control algorithms for realizing higher plant performance level. Advanced control algorithms of practical interest in power plant control are Kalman filtering, state observer techniques, self-tuning regulators, and expert systems.

The *Kalman filtering* techniques have been used to achieve tighter temperature control, which reduces temperature excursions to within + or –4ºC from that of + or –8 to 9ºC in conventional controls. The improvement of performance with such techniques is well established in the case of temperature controls. It is also clear that in the systems where a large amount of process noise is inherent, Kalman filtering can play a useful role. Further, for any process which has inherent process lags, predictive control would be useful.

The second area is the use of *adaptive control* or *self-tuning regulators*. In such control schemes, the controller parameters adjust to change in operating conditions or equipment over time. When the operating conditions change, the controller can adjust its parameters to achieve a wide range of optimal control. When the various elements of the mechanical system change, the controller can adjust its parameters to maintain the same loop parameters again.

Also, expert systems can be used to solve many problems encountered in the power plant. Typical application areas are:

1. Power plant and DCS diagnostics, on-line diagnostics of turbine generator system, etc.
2. Alarm processing, based on mathematical model of the plant
3. Operator guidance under emergency conditions and adoption of control strategies to changing conditions.

A power plant can have a considerable amount of alarm conditions. The expert system can analyze the alarm conditions and explain what is going wrong.

False alarms can be costly to the utility when a unit is shut down unnecessarily. A number of alarms can be in effect false, if they occur at a time when the reading is irrelevant. The expert system can filter such alarms before being presented to the operator. Turbine-generator diagnostics has been performed, based on sensor data collected through the plant data acquisition system.

An actual implementation of DCS system configuration, including advanced control applied to boiler control, is shown in Figure 4.18 as applied to a liquefied natural gas firing plant. This example includes steam temperature prediction control. The whole system is based on hierarchical structure, consisting of three levels of control. Unit control level (Level-III) handles plant control and information system, common to the unit. On the lower functional group level, the control functions are distributed into Level-II plant controllers. At this level, each plant controller operates autonomously. It adjusts the control mode of the plant according to the availability of the plant information at that time. At the drive control level, the functions are further distributed into Level I controllers and drive control modules, which provides distribution of the plant control function down to each drive level.

Two distinct plant communication networks, high speed (HS) network and low speed (LS) network, provide the communicating path between controllers and information systems at function group and the drive control level.

All controllers are accessible by engineer's console, and all plant parameters and signals can be tuned and modified through the console.

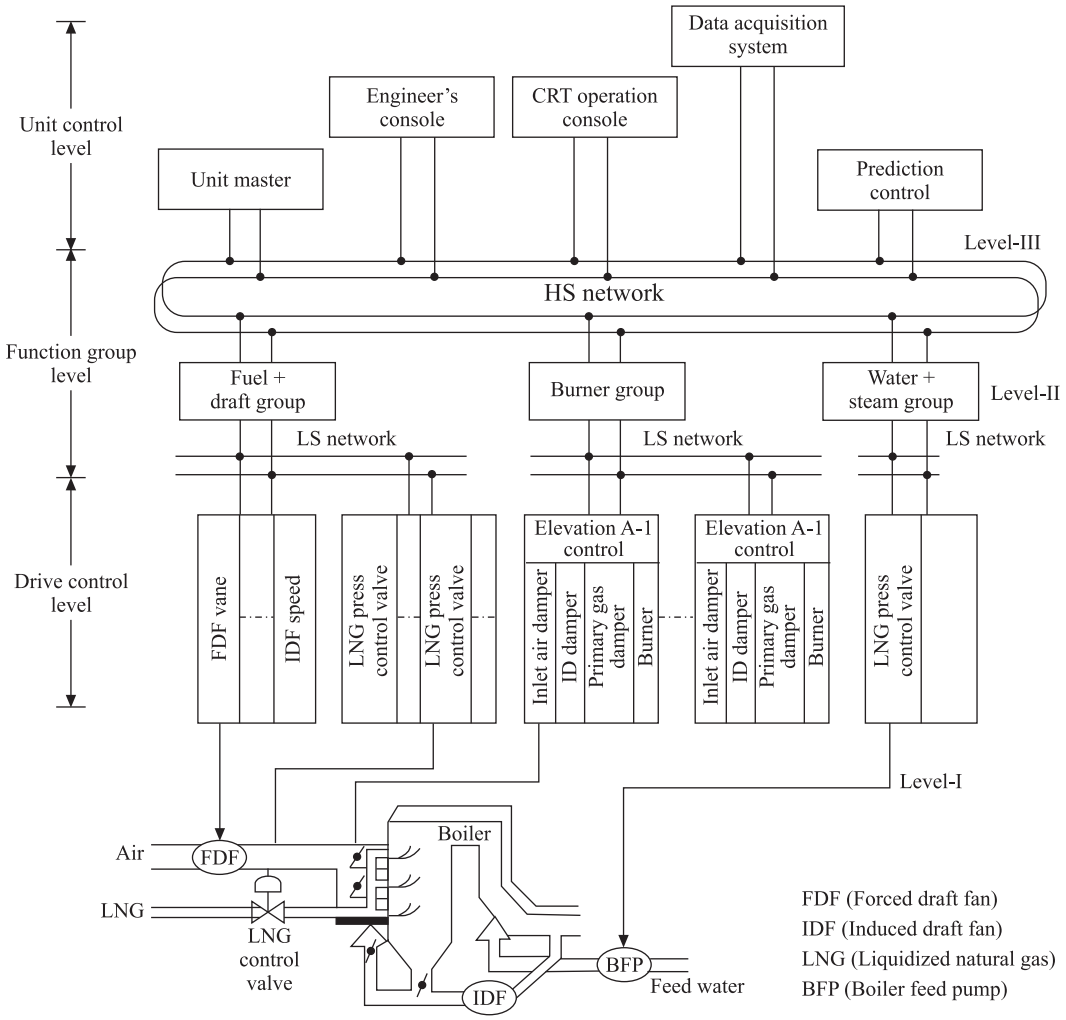


Figure 4.18 Power plant automation.

WORKED-OUT PROBLEMS

PROBLEM 4.1 The fuel used in the boiler has the following composition by weight. If 20% excess air is allowed, calculate the following per kg of fuel used.

(a) Theoretical air required for complete combustion i) by weight and ii) by volume.

(b) Total air required i) by weight and ii) by volume

(c) Products of combustion by volume and weight, assuming complete combustion with excess air.

Composition of fuel by weight %

Carbon	60%
Hydrogen	20%

Sulphur	5%
Oxygen	5%
Nitrogen	5%
Ash + water	5%
Total	100%

Solution:

(a) (i) Theoretical air required by weight:
Assuming 1 kg of fuel,

$$\text{Oxygen required to burn carbon} = C \times \frac{8}{3}$$

$$= 0.6 \times \frac{8}{3}$$

$$= 1.6 \text{ kg}$$

Oxygen required to burn hydrogen: $H_2 \times 8 = 0.2 \times 8 = 1.6$ kg
Oxygen required to burn sulphur: S = 0.05 kg
Oxygen available in the fuel itself: 0.05 kg
$\therefore$ Total oxygen required: 1.6 + 1.6 + 0.05 – 0.05 kg = 3.2 kg

$$\text{Theoretical air required by weight} = \frac{3.2}{0.23} = 13.9 \text{ kg}$$

(ii) Theoretical volume of air $= \frac{3.2}{32} \times 22.4 + \frac{(13.9 - 3.2)}{28} \times 22.4$

$= 2.24 + 8.56 = 10.8 \text{ Nm}^3$

(b) Excess air of 20% allowed:
(i) Total air required by weight: $13.9 \times 1.2 = 16.68$ kg
(ii) Total air required by volume: $10.8 \times 1.2 = 12.96 \text{ Nm}^3$

(c) Products of combustion:

Products of combustion	By weight	By volume
$CO_2 = C + C \times \frac{8}{3}$	$= 0.6 + 0.6 \times \frac{8}{3}$ $= 2.2$ kg	$\frac{2.2}{44} \times 22.4 = 1.12 \text{ Nm}^3$
$H_2O = H_2 + H_2 \times 8$	$= 0.2 + 0.2 \times 8$ $= 1.8$ kg	$\frac{1.8}{18} \times 22.4 = 2.24 \text{ Nm}^3$
$SO_2 = S + S$	$= 0.05 + 0.05$ $= 0.1$ kg	$\frac{0.1}{64} \times 22.4 = 0.035 \text{ Nm}^3$

$N_2 = N_2 + \text{Total air} \times 0.77 \quad = 0.05 + 16.68 \times 0.77 = 12.9 \text{ kg}; \quad \frac{12.9}{18} \times 22.4 = 10.3 \text{ Nm}^3$

$O_2 = (\text{Total air} - \text{Theoretical air}) \times 0.23 \quad = (16.68 - 13.9) \times 0.23 = 0.66 \text{ kg}; \quad \frac{0.66}{32} \times 22.4 = 2.24 = 0.46 \text{ Nm}^3$

PROBLEM 4.2 The composition of the fuel used in the boiler by weight is given below:

Carbon	70%
Hydrogen	10%
Sulphur	2%
Oxygen	5%
Ash	13%
Total	100%

(a) Calculate the amount of theoretical air required per kg of fuel.
(b) Calculate the total air requirement if 5% excess air by weight is required?
(c) Calculate the following products of combustion by weight if complete combustion has taken place with the excess air.
(i) CO_2, (ii) H_2O, (iii) SO_2 and (iv) O_2

Solution:

(a) Theoretical air required by weight

$$= \frac{\left(\frac{8}{3} \times 0.7\right) + (8 \times 0.1) + 0.02 - 0.05}{0.23}$$

$$= 11.465 \text{ kg}$$

(b) Total air required with 5% excess air

$$= 11.465 \times 0.05 + 11.465$$

$$= 12.038 \text{ kg}$$

(c) Products of combustion:

(i) CO_2

$$\text{Weight of } CO_2 = C + \frac{8}{3}C$$

$$= 0.7 + \frac{8}{3} \times 0.7$$

$$= 2.567 \text{ kg}$$

(ii) H_2O

$$\text{Weight of } H_2O = H_2 + 8H_2$$

$$= 0.1 + 8 \times 0.1$$

$$= 0.9 \text{ kg}$$

(iii) SO_2

Weight of SO_2 = S + S

= 0.02 + 0.02

= 0.04 kg

(iv) O_2

Weight of O_2 = Excess air × 0.23

= 11.465 × 0.05 × 0.23

= 0.32 kg

PROBLEM 4.3 The results of tests conducted to determine the thermal efficiency of a multi-fuel-fired boiler are given below. Calculate the thermal efficiency of the boiler by input-output method.

Period of test conducted : 3 shifts of 8 hrs each

Fuel input details:

Fuel 1: Coal with average calorific value of 8000 kcals/kg
Average rate of coal input per shift for three shifts: 15 T/hr, 12 T/hr and 18 T/hr.

Fuel 2: Natural gas with calorific value of 6000 kcals / Nm^3
Rate of flow kept constant at 15,000 Nm^3/hr throughout 3 shifts.

Fuel 3: Industrial process gas with calorific value of 4000 kcals/Nm^3
Rate of flow varied as below:
First 4 hours : 15,000 Nm^3/hr
Next 16 hours : 14,000 Nm^3/hr
Last 4 hours : 16,000 Nm^3/hr

Steam output details:

Heat content of the steam generated = 1.9×10^6 kcals/T

Steam flow reading:

First 4 hours: 1,00 T/hr
Next 16 hours: 95 T/hr
Last 4 hours: 105 T/hr

Solution: Input heat content through coal

$$= 15 \frac{T}{hr} \times 8000 \frac{\text{kcals}}{\text{kg}} \times 8 \text{ hrs}$$

$$+ 12 \frac{T}{hr} \times 8000 \frac{\text{kcals}}{\text{kg}} \times 8 \text{ hrs}$$

$$+ 18 \frac{T}{hr} \times 8000 \frac{\text{kcals}}{\text{kg}} \times 8 \text{ hrs}$$

$$= (960 + 768 + 1152) \times 10^6 \text{ kcals} = 2880 \times 10^6 \text{ kcals}$$

Input heat content through natural gas

$$= 15,000 \frac{\text{Nm}^3}{\text{hr}} \times 6000 \frac{\text{kcals}}{\text{Nm}^3} \times 24 \text{ hrs}$$

$$= 2160 \times 10^6 \text{ kcals}$$

Input heat content through process gas

$$= \left(15,000 \frac{\text{Nm}^3}{\text{hr}} \times 4000 \frac{\text{kcals}}{\text{Nm}^3} \times 4\text{hrs}\right)$$

$$+ \left(14,000 \frac{\text{Nm}^3}{\text{hr}} \times 4000 \frac{\text{kcals}}{\text{Nm}^3} \times 16 \text{ hrs}\right)$$

$$+ \left(16,000 \frac{\text{Nm}^3}{\text{hr}} \times 4000 \frac{\text{kcals}}{\text{Nm}^3} \times 4 \text{ hrs}\right)$$

$$= (240 + 896 + 256) \times 10^6$$

$$= 1392 \times 10^6 \text{ kcals}$$

$\therefore$ Total input heat content $= (2880 + 2160 + 1392) \times 10^6$ kcals

$$= 6432 \times 10^6 \text{ kcals}$$

Output heat content of the steam generated

$$= 100 \frac{\text{T}}{\text{hr}} \times 4 \text{ hrs} \times 1.9 \times 10^6 \frac{\text{kcals}}{\text{T}}$$

$$+ 95 \frac{\text{T}}{\text{hr}} \times 16 \text{ hrs} \times 1.9 \times 10^6 \frac{\text{kcals}}{\text{T}}$$

$$+ 105 \frac{\text{T}}{\text{hr}} \times 4 \text{ hrs} \times 1.9 \times 10^6 \frac{\text{kcals}}{\text{T}}$$

$$= (760 + 2888 + 798) \times 10^6 \text{ kcals}$$

$$= 4446 \times 10^6 \text{ kcals}$$

$\therefore$ Thermal efficiency $= \dfrac{\text{Output heat content}}{\text{Input heat content}} \times 100\%$

$$= \frac{4446 \times 10^6}{6432 \times 10^6} = 69.1\%$$

PROBLEM 4.4 The heat losses calculated with the help of analysers, temperature measurements, etc. are given below for the boiler under test in Problem 4.3.

1. Heat loss due to dry chimney gas: 400×10^6 kcals.
2. Heat loss due to moisture in the fuel: 260×10^6 kcals
3. Heat loss due to moisture formation while burning: 220×10^6 kcals

4. Heat loss due to combustibles in flue gas: 720×10^6 kcals
5. Heat loss due to combustibles in refuse: 100×10^6 kcals
6. Heat loss due to wall losses: 160×10^6 kcals

(a) What is the quantum of heat loss unaccounted by taking the efficiency of the boiler through input-output method into account?
(b) If the heat loss unaccounted for is assumed reasonably as 90×10^6 kcals, findout the efficiency of the boiler by heat loss method.
(c) What is the difference between two efficiencies?

Solution:

(a) Total heat input = 6432×10^6 kcals.

$$\text{Efficiency} = \frac{\text{Input} - \text{Losses}}{\text{Input}} \times 100 = 69.1 \text{ from problem } \#\ 3$$

$$\therefore \quad \text{Losses} = \left(\frac{69.1 \times 6432 \times 10^6}{100} - \text{Input} \right)$$

$$= (6432 \times 10^6 - 4444.5 \times 10^6) \simeq 1988 \times 10^6 \text{ kcals}$$

$\therefore$ Unaccounted heat loss = Total heat loss – Other six heat losses

$$= 1988 \times 10^6 - [400 + 260 + 220 + 720 + 100 + 160] \times 10^6 \text{ kcals},$$

$$= (1988 - 1860) \times 10^6$$

$$= 128 \times 10^6 \text{ kcals}$$

(b) If unaccounted heat loss = 90×10^6 kcals,

$$\text{Total losses} = (400 + 260 + 220 + 720 + 100 + 160 + 90) \times 10^6 \text{ kcals}$$

$$= 1950 \text{ kcals}$$

$$\therefore \quad \text{Efficiency} = \frac{\text{Input} - \text{Losses}}{\text{Input}} \times 100\%$$

$$= \frac{6432 - 1950}{6432} \times 100\%$$

$$= 69.7\%$$

(c) Difference between two efficiencies:
Efficiency by input – Output method = 69.1%
Efficiency by heat loss method = 69.7%
Difference = 69.7 – 69.1 = 0.6%

PROBLEM 4.5 The total input heat content of fuels supplied during a specific period to a boiler is $100{,}000 \times 10^6$ kcals. The output heat content of the steam generated is $75{,}000 \times 10^6$ kcals.

(a) Calculate the boiler efficiency.
(b) If the heat content carried away by the blow down is 2000×10^6 kcals, calculate the boiler thermal efficiency.

Solution:

(a) Boiler efficiency $= \dfrac{\text{Output}}{\text{Input}} \times 100\%$

$$= \frac{75,000}{100,000 \times 10^6} \times 100 = 75\%$$

(b) Boiler thermal efficiency: Sometimes the heat content carried away by blow down is considered as the already converted energy, i.e. the fuel has burnt and given heat energy to blow down (though it is not a useful energy as far as steam generated is concerned).

$$\therefore \text{ Thermal efficiency} = \frac{\text{Output heat through (steam generated + blow down)}}{\text{Input heat from fuels}} \times 100$$

$$= \frac{(75,000 + 2000) \times 10^6 \text{ kcals}}{100,000 \times 10^6 \text{ kcals}} \times 100\%$$

$$= 77\%$$

EXERCISES

1. What are the requirements for efficient combustion of fuel?
2. What are the two different ways of calculating boiler efficiency?
3. Explain the seven types of heat losses encountered in a boiler.
4. Explain the heat balance method in the evaluation of heat losses due to heat radiation and due to combustibles in refuse.
5. What is the function of a master controller in a power station? How does it differ from boiler load-sharing controllers?
6. How is PLC and SCADA combined in a DCS?
7. Write the equation representing the complete combustion of ethane in oxygen.
8. State the causes for heat loss due to incomplete combustion.
9. Briefly discuss about the chemistry of combustion and determination of efficiency of boilers.
10. Give typical value of efficiency in thermal power plants.
11. What is meant by excess air? How is it different from theoretical air?
12. What are the different maintenance practices followed for power plant instruments?
13. Why calibration is needed for power plant instruments? At what frequency the calibration is needed?
14. Name some of the critical parameters whose instruments are to be calibrated very often?
15. Why interlocks are important in power plant boilers?
16. What are the differences in carrying out interlock functions through relays and PLCs?
17. What is a fieldbus? Explain.

18. Calculate the boiler efficiency if fuel input for a day is natural gas with calorific value of 6000 kcals/Nm^3 at the rate of 2000 Nm^3/hr and the steam output with the heat content of 2 $\times 10^6$ kcals/ T is 4 T/hr.

19. For the given fuel composition, calculate the theoretical air required by weight per kg of fuel.

Carbon	= 70%	Oxygen	= 5%
Hydrogen	= 10%	Nitrogen	= 5%
Sulphur	= 5%	Ash	= 5%

20. Write the equation representing the complete combustion of methane.

21. Name two parameters, out of which one is selected normally for master controller.

22. Coal with calorific value of 8000 kcals/kg is fed at the rate of 20 T/hour throughout the day. If the steam generated per hour is 70 T, calculate the boiler efficiency assuming the heat content of steam produced as 1.8×10^6 kcals/T. Also calculate the thermal efficiency of the boiler if the average blow down is 2 T/hr with a heat content of 0.5×10^6 kcals/T.

23. What is meant by intrinsic safety of instruments?

24. Name various approaches for protection of explosion?

25. List out basic safety interlocks used in boilers.

26. Explain the sequencing of burner operations.

27. Explain the overall PLC with a schematic.

28. What is called SCADA? How is it useful for power plant operation?

29. What are the different configurations of process control networks?

30. Name some of the types of fieldbus.

31. Explain about OSI 7–layer protocol with the functions of each layer used.

32. What are the advantages of direct digital control (DDC) system?

33. How are the functions of DDC and PLC combined in distributed control system (DCS)?

34. What are the advantages derived by using DCS for boiler controls?

35. What are the different levels of controls enforced in a DCS system?

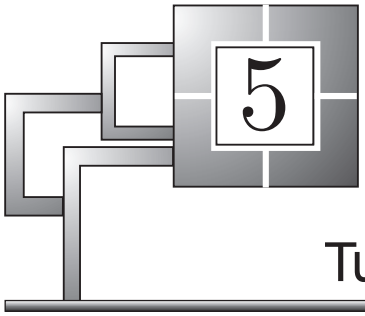
36. Name the different buses used in DCS.

37. What are the different displays available for man-machine communication in a DCS system?

38. Describe the characteristics of a fieldbus.

39. How system reliability is enhanced through redundancy in DCS?

40. Draw a schematic diagram showing different levels of DCS with different buses for power plant automation.



Turbine—Monitoring and Control

5.1 INTRODUCTION

In thermal power stations, electric power is generated by rotating the rotor shaft of an alternator with the help of steam turbine. A steam turbine extracts energy from steam generated from the boilers. The high pressure and high temperature steam supplied by the boiler enters a turbine with a lot of heat energy in it. A steam turbine continuously converts that heat energy into shaft work. The utilized steam is then exhausted to a condenser at low pressure and low temperature. Excellent speed stability is possible with appropriate control equipment. The stability of speed is one of the most important criteria for the prime movers of electric generators.

5.1.1 Classification

Two main parts of a steam turbine are nozzles and blades. The heat energy to rotational mechanical energy conversion takes place in two steps. Nozzles receive steam at high temperature and pressure, expand and allow the steam to come out of them at a high velocity. The blades mounted on a wheel receive the high velocity jets from the nozzles. The impinged steam produces torque on the rotating wheel while losing its momentum and deflecting by an angle. The turbines are classified mainly into two categories, based on the types of blades used and the method of energy transfer. They are:

1. Impulse turbines
2. Reaction turbines

Impulse turbines

The complete pressure drop of the steam takes place in the nozzles and the wheel rotates only due to the impulsive effect of the jets coming out of nozzles. The angular momentum absorbed by the

wheel in producing shaft work is equal to the momentum of steam jets at inlet to the blades minus the momentum of jets at exit from the blades.

Reaction turbines

The pressure drop occurs both in the nozzles and in the moving row of blades. The expansion of steam in the blades increases the kinetic energy of the steam. The increase in kinetic energy causes reaction in the opposite direction. Hence the moving blades rotate due to both the impulsive effect of the jets and the reactive action. Though such turbines are called *reaction turbines*, they are actually impulse-reaction turbines.

5.1.2 Instrumentation Control Points of View

For instrumentation and control point of view, the turbines may be classified based on the process conditions. They are basically classified into the following three categories:

1. Condensing turbine
2. Non-condensing turbine
3. Extraction turbine

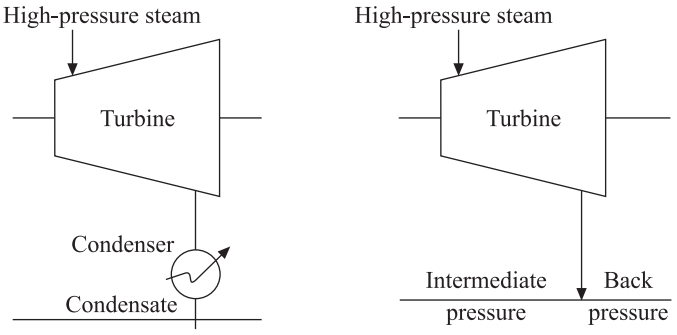
Condensing turbine

The input to the turbine may be from a single source or from a number of boilers connected to a steam bus and then supplied. The output may be 'condensing' in which the exhaust pressure is sub-atmospheric (vacuum). The condensed water is recirculated back into feed water stream to avoid treatment of more freshwater (make up water). Here the makeup water requirement is kept at minimum.

Non-condensing turbine

The input to the turbine is similar to that of condensing turbine, but the output may be 'non-condensing' in which the exhaust pressure is greater than atmospheric. Such a turbine is also called *back pressure turbine*. The steam that exhausted with some pressure may be utilized as process steam for the other purposes in the plant. Such a steam is called *process steam* or *intermediate pressure steam* or *low pressure steam*.

Both condensing and non-condensing turbines are shown schematically in Figure 5.1.



(a) Condensing turbine (b) Non-condensing (Back pressure) turbine.

Figure 5.1 Condensing and non-condensing turbines.

Extraction turbine

Both in condensing and non-condensing turbines, the outlet from the turbine is only one. One or two more outlets may be provided to extract steam at different pressures for other uses. Such a turbine is called *extraction turbine*. It may be condensing or non-condensing. One such extraction turbine which is also condensing is shown in Figure 5.2.

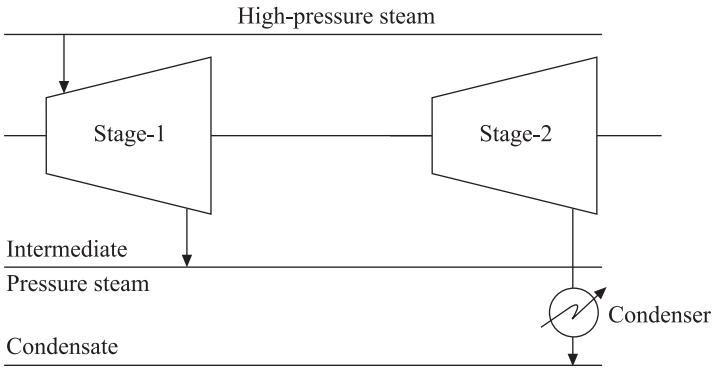


Figure 5.2 Extraction turbine.

Topping and bottoming turbines

The non-condensing back pressure turbine has its inlet connected to the plant's high pressure header. Its outlet is connected to a intermediate pressure header from where the steam is supplied for other purposes. As this turbine is using steam from the 'top' of the pressure range in the plant, it is also called 'topping turbine' as displayed in Figure 5.1(b).

Sometimes the exhaust of one turbine is used as inlet to another turbine whose outlet is condensed. Such a turbine is called a *bottoming turbine* as it uses low-pressure steam as inlet as shown in Figure 5.3.

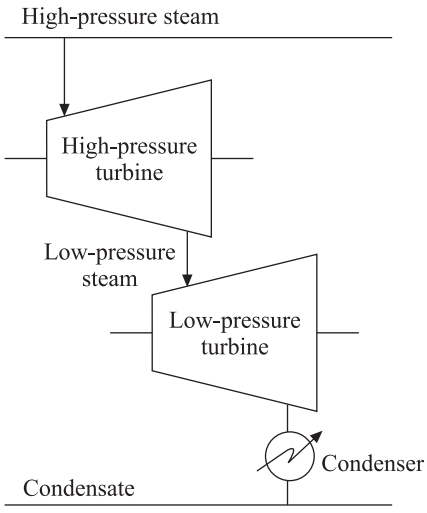


Figure 5.3 Bottoming turbine.

There is also a rare combination of mixed input and extraction type available. Here a port is provided for extracting or inducting steam intermediately when additional energy is required. Such a unit is called an 'induction-extraction' turbine.

5.1.3 Principal Parts of Steam Turbines

The following are the principal parts of steam turbine:

1. Rotor
2. Casing/shell
3. Bearings
4. Shaft seals
5. Steam control system
6. Oil system.

The various elements of the steam turbine are shown in Figure 5.4.

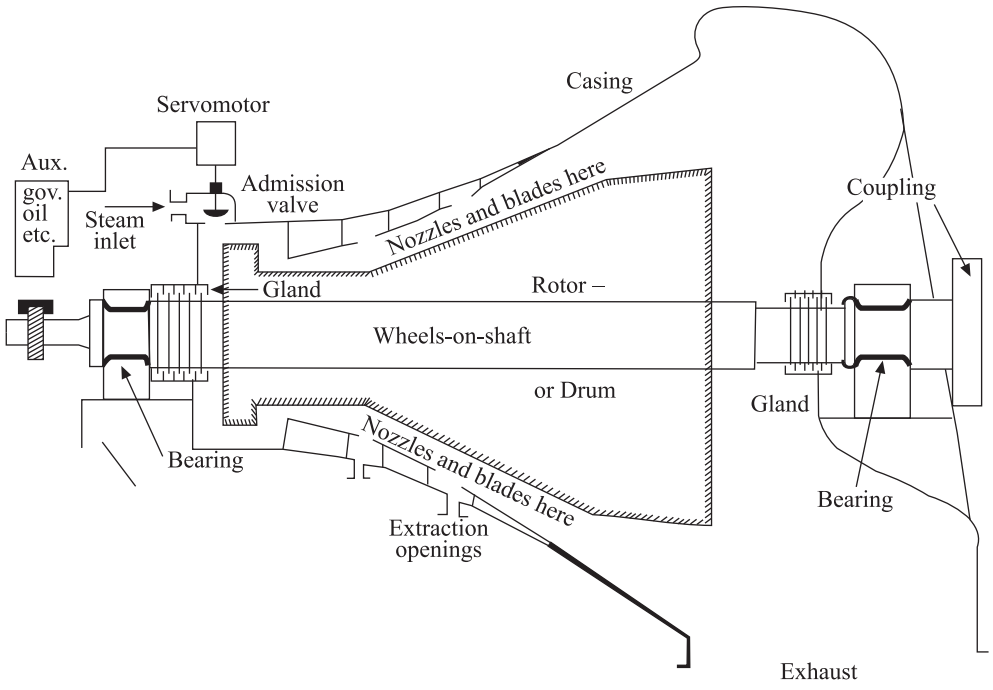


Figure 5.4 Elements of the steam turbine.

Rotor

This is the main moving element of a turbine. In impulse turbines it is a shaft on which the wheels carrying the blades are mounted. The rotor of a reaction turbine is a drum. It will be stepped or tapered in order to increase its diameter toward the low-pressure end. The rotor is supported through bearings mounted on both sides of the turbine. It is coupled to the rotor of the alternator

which is again supported through bearings mounted on both sides of the alternator. The converted rotational energy of the turbine is transmitted to the alternator rotor which in turn, converts the mechanical rotational energy into electricity. A simple single stage turbo-alternator will have at least four bearing supports.

Casing/shell

Casing is the principal stationary element, often called the *shell*. It surrounds the rotor and holds, internally, any nozzles, blades, and diaphragms that may be necessary to control the path and the physical state of the expanding steam. The bearings, auxiliaries and steam lines are attached to the casing or are an integral part of it. It is also shaped to become the main frame and support of the assembled turbine. The casing is normally thermally insulated from outside to prevent radiation losses. The casing/shell temperatures are measured at different locations for monitoring purposes.

Bearings

The main bearings of a single-stage turbine are two in number (excluding alternator bearings which are additional two in number), placed outboard of the shaft seal. Most journals run in plain babbitted bearings. Some small turbines are ring-oiled from reservoirs, others follow large turbine practice with pressurized oiling systems. Thrust is carried by separate thrust bearings, plain or ball. Where the large-end thrusts are produced, as in the case of reaction turbines, they are mainly neutralized by steam-loaded balance plates on the rotor.

The amount of heat energy dissipated because of the friction in the bearings depends mainly on the turbine-load conditions. This may result in increase of bearing temperature which can be controlled through lubrication of the bearings. The bearings temperature measurement is also a way of detecting deterioration in bearings before complete mechanical failure. Hence a lubrication system with pressure/flow, temperature and/or oil tank level controls become part of the bearings systems.

Shaft seals

Where the shaft emerges from the casing it needs sealing to prevent steam outflow at the high-pressure end and air inflow at the vacuum end. On small noncondensing turbines, this is accomplished by mechanical sealing rings; however these are not practical if the shaft diameter is large. Labyrinth glands with steam or water sealing at the condenser end are employed on all large turbines. Multistage internal turbines must also be internally sealed between the shaft and diaphragms.

Steam control system

Flow of the steam through a turbine is usually regulated so as to produce constant rotative speed in the presence of variable power demand. This is always the case where the turbine is used for electric generation. Control is exercised by varying the quantity and pressure of the steam flowing through the turbine. If quantity control could be had alone, it would be employed, but the turbine has fixed-size nozzles and pressure control is the most practical method of varying quantity. In large turbines, power is varied with minimum throttling by subdividing the first stage nozzles into

groups which come into action in sequence as load is increased. However, beyond the first stage the entire nozzle group is always in action, and pressure and quantity are variable when power is changed.

Oil system

Oil is required for lubricating the bearings. Most turbines use the oil-pressure system for both bearing lubrication and governor servomechanism operation. An integral oil pump, driven from the main shaft, provides the pressure for oil relays and governor valve-operating cylinders. The same oil, when reduced somewhat in pressure, serves for circulating to the bearings. An oil reservoir, oil filter, and oil cooler are included in this system. Sometimes a separately-driven emergency oil pump is provided, (in case the main oil supply to a large turbine fails, the bearings would be ruined before the rotor came to rest) even though the fault were immediately detected and the emergency valve tripped. This is because of the enormous store of energy in the massive rotor running at 1500 or 3000 rpm.

Turbines may have all the aforementioned components, yet they vary in several ways other than the size.

5.2 Turbine Steam Inlet System

The simplest application is one in which a turbine is used to operate a mechanical load at a constant speed. The mechanical load in our case is electric generator coupled to the turbine. Steam is supplied from the common steam bus/header and condensed in the turbine. A speed controller (governor) senses shaft speed and corrects it to a set point by manipulating the valve supplying steam to the turbine. Variations in load, caused by either shaft loading or variations in supply header pressure, affect the balance between the energy supplied to the turbine from the steam system and the work removed from the turbine's shaft. If the net change is positive due to availability of more energy than is being used, the shaft will speed up. The governor will detect the increase in speed and act to eliminate it. The only way of doing so is to reduce the energy supplied to the turbine by closing the supply valve. If the net change were negative, the shaft would slow down. The governor would respond by opening the supply valve. Also in case of emergency, the steam supply has to be stopped totally and immediately. A quick closing valve or a quick shut-off valve is installed to take care of this requirement. Hence to serve the above functions, the steam inlet system will have the following provisions.

1. Inlet valve arrangements
2. Inlet flow, pressure and temperature measurements
3. Governors.

5.2.1 Inlet Valve Arrangements

In a typical installation the steam line leading to the turbine from the steam main bus/header will contain a gate valve for the purpose of isolating the turbine from the steam header. It is fully opened when preparing to start the turbine. Next in sequence is the turbine throttle valve. This is manually operated and used to regulate the rate of steam at the time of starting the turbine. When the turbine is warmed and up to speed, this valve is left fully open. Large high pressure units often

do not have such a valve, but have a manual override on the governor system for use during starting. An emergency trip valve may either be built into the throttle valve or become a separate unit following it. This is tripped shut if the turbine over speeds because of governor defects. It can also be interlocked to act on other emergencies such as generator under voltage, loss of lube oil pressure, water in extraction lines, etc. An emergency switch is also provided to the operator of the turbine to trip the unit by pressing the switch which in turn operates the emergency trip valve. Following the emergency valve the steam flows through the speed control valve/governor valve and into the first stage nozzles, after which it expansively flows through the turbine without further control.

5.2.2 Inlet Measurements

Certain monitoring instruments are provided in the steam inlet line. Steam pressure, flow and temperature are measured before it enters the turbine. The measurements are carried out as was discussed in Section 2.1 of Chapter 2. The signals are normally transmitted and displayed in boiler control room as well as in electrical control room. They are grouped together with the power generated by the concerned turbo-alternator so that the boiler operator and the operator of electrical system are facilitated with the information. It helps them to monitor and take appropriate actions whenever required. Steam flow signals and power generated signals are integrated for correlating the specific power generation (MW/Tonne of steam) ratio for accountability. The amount of energy that is extracted from the steam can be found by knowing the pressure and temperature of the inlet and outlet steam and finding out the enthalpy drop across the machine. Enthalpies can be found out from Mollier diagram which relates enthalpy, steam pressure and steam temperature.

5.2.3 Governors

The valve between the inlet of the turbine and the steam supply point is common in all turbine applications. It is normally installed after the emergency valve as explained in Section 5.2.1. This valve is used to control the amount of steam to the turbine. The change in position of the valve changes the energy input to the turbine. Electrical load demand changes from time to time. To balance the changes in electrical load, corresponding changes in the steam input has to be done. This valve is used for this purpose and hence is the primary means of controlling the unit. A functional relationship between steam flow and shaft horse power exists. Shaft horse power can be controlled by controlling the speed of the shaft. This required speed control is always accomplished by a governor. Governors may be mechanical, hydraulic, or electrical. All these governors finally operate a pilot valve which in turn, controls the turbine inlet valve in response to shaft speed.

Mechanical governors use the good old fly ball mechanism. Centrifugal mechanism is used in hydraulic governors to perform the same function, but in a different way. The speed of the turbine shaft is measured by an electronic tachometer and given to a controller. The control signal may operate either electric, pneumatic or hydraulic actuator which is physically linked to the inlet valve. Figure 5.5 shows turbine steam inlet system covering all those elements discussed above for proper understanding.

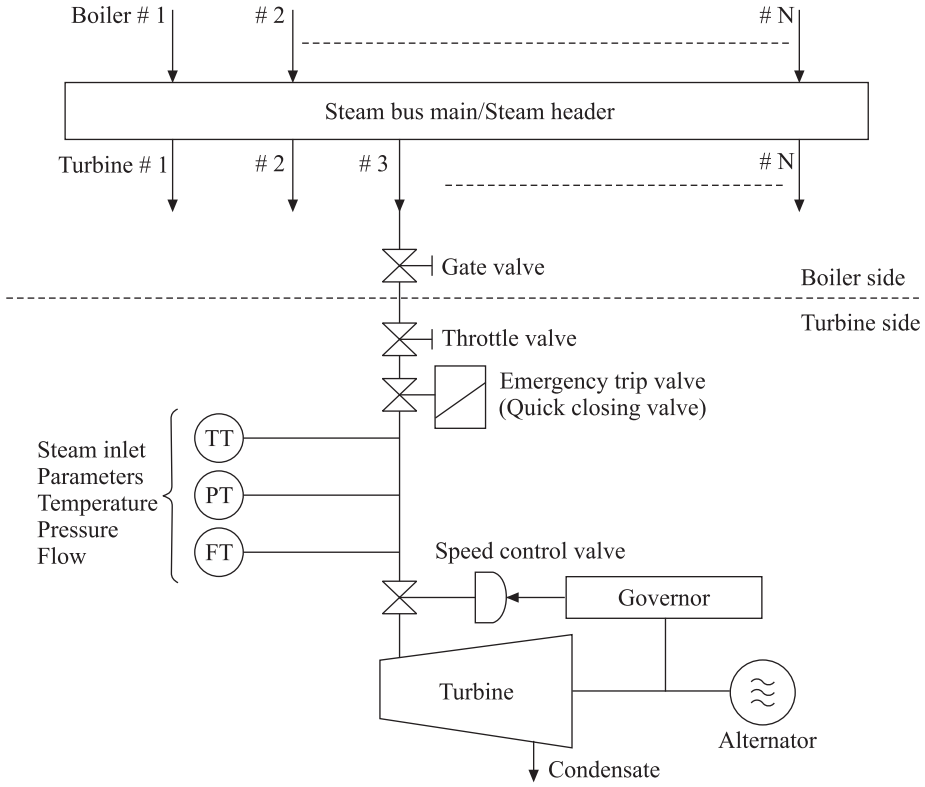


Figure 5.5 Turbine steam inlet system.

5.3 TURBINE MEASUREMENTS

Certain supervisory measuring instruments are necessarily to be provided for the safe and effective operation of the turbine. The important parameters which are to be measured are classified into three groups as below:

Group–I Process parameters:

1. Steam pressure
2. Steam temperature
3. Steam Flow
4. Condenser level
5. Condenser vacuum
6. Condensate flow

Group–II Mechanical parameters:

1. Speed
2. Vibration and displacement
3. Bearing temperature
4. Lube oil parameters
5. Casing/shell temperatures

Group–III Electrical parameters:

1. Voltage
2. Current
3. Power
4. Reactive power
5. Energy
6. Frequency
7. Power factor

5.3.1 Process Parameters

We consider under this group the measurements related to steam and water.

Steam pressure

Pressure transmitter is provided to measure the steam inlet pressure and transmit to the control room. In addition, pressure gauges of Bourdon tube type are provided to measure the pressure of steam at various points and displayed locally for operator's guideline. Main steam pressure, steam pressure after inlet valves, stage steam pressures and exhaust steam pressure are such points.

Steam temperature

Temperature transmitter is provided with thermocouple, compensating leads and cold junction compensation for measurement of inlet steam temperature. In addition, steam temperatures after inlet valve, stage and exhaust are measured and locally displayed with the help of gas-filled pressure thermometers.

Steam flow

Inlet steam flow measurement is carried out with orifice head producer installed in the steam line. The differential head produced is measured using differential pressure transmitter and square rooted to get linearised flow reading. Also the flow is temperature and pressure corrected to have a correct flow reading even if pressure and temperature are different from design pressure and temperature. The steam flow is also integrated for accounting and analysis purposes. Knowing the total steam consumed by a turbine for a specific period and the power generated for the same period, one may be able to analyse the performance of the turbine. Steam consumed per MW of power produced is called *specific steam consumption*. Turbine performance may be rated according to this factor among different turbines in the power plant.

Condenser level

A condenser is a unit where the exhaust steam from the turbine is condensed. It operates at a pressure lower than atmospheric pressure, i.e. vacuum. There are two objectives of using a condenser in a steam plant:

1. To reduce the turbine exhaust pressure so as to increase the specific output of the turbine.
2. To recover high quality feed water in the form of condensate and feed it back to the steam generator without any further treatment. As a result, only the make-up water to replenish the water losses in the cyclic plant needs to be treated.

As the exhaust steam gets condensed, the water level in the condenser vessel changes. It is very necessary to know the level in the condenser for the operation point of view. The continuous level measurement is done as applicable to a pressurized vessel. Also at different levels of the condenser, the level switches are provided for annunciation purpose.

Condenser vacuum

The vacuum pressure created in the condenser helps to reduce the turbine exhaust pressure so as to increase the specific output of the turbine. If the circulating cooling water temperature in a condenser is low enough, it creates a low back pressure (vacuum) for the turbine. A condenser by lowering the backpressure, say, from atmospheric pressure (760 mmHg) to around 50 mmHg, increases the plant efficiency and reduces the steam flow for a given output. The lower the pressure, the greater the output and efficiency. Hence, it is important to measure the vacuum pressure created in the condenser.

Basically the vacuum pressure gage, also called *barometric gage*, is a U-tube type as shown in Figure 5.6. A Torricelli vacuum (0 mmHg) is maintained in the space above the mercury in the barometric chamber. When the test pressure in the float chamber is also equal to full vacuum, the mercury level in both chambers is the same. As the pressure in the float chamber rises, the mercury level in the float chamber is depressed, and the float whose core is of magnetic material, moves accordingly. The position of the float is sensed by a magnet, embracing the float chamber, and transmitted to the indicating and recording instruments. The range of the instrument, used in turbines, is normally 0 to 200 mmHg.

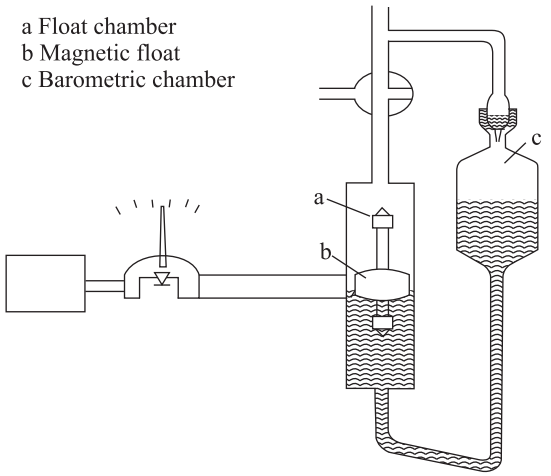


Figure 5.6 Barometric gage with magnetic float.

The three-way plug permits to test the unit, in view of possible vacuum loss caused by evaporation from the mercury or vessel walls. The plug is turned to allow air to enter the float chamber, thus forcing the mercury against the seal of the barometric chamber. Any traces of gases or vapours will be removed and drawn off by evacuation through the riser tube. The seal will not pass mercury. Little mercury above the seal acts as a non-return device, and will prevent any traces of gases from reentering the barometric chamber.

Condensate flow

The steam after getting condensed in the condenser becomes condensate water. This water is pumped back, by a condensate pump, into the feed water system. The measurement of condensate flow helps the operator to decide about the quantity of makeup water and hence, the amount of raw water to be treated, because the condensate plus make up water meets the feed water demand of the boiler. The measurement is generally carried out by installing a head producer, say, orifice, and using flow transmitter.

5.3.2 Mechanical Parameters

In this section we deal with measurements related to mechanical equipment like, turbine rotor, bearings, couplings, casing/shell, support systems etc.

Speed

Turbine shaft speed is very important as the speed decides the frequency of the electrical power generated by the alternator coupled with the turbine. We know,

$$\text{Frequency } (f) = \frac{NP}{120}$$

where P = Number of poles
N = Speed in rpm
f = Supply frequency in Hz

As our power supply frequency is fixed at 50 Hz, we have the speed for bipolar [Number of poles (P) = 2] generator as 3000 rpm $\left(N = \frac{120 \times 50}{2}\right)$ and for 4 pole machine as 1500 rpm $\left(N = \frac{120 \times 50}{4}\right)$. It becomes essential to control the speed of the turbine to maintain the supply frequency which is very important from the point of consumers' view. Hence the speed of the turbine is always measured and displayed in the control room. In addition, the speed signal is utilized in the speed control loop to automatically maintain the turbine speed.

Indirect way of measuring speed is by measuring the generator frequency. But in practice, turbine shaft speed is measured either by analog tachogenerator or by digital tachogenerator. A.C. tachogenerator, D.C. tachogenerator, induction type speed sensor and magnetic type speed sensor are some of the speed measuring devices. Contact type, where the tachogenerators are directly coupled with the turbine shaft at the end and non-contact type, where magnetic pulse type sensors are employed, tachometers are also possible to be employed. The output of the speedometers are always converted into a standard electrical signal (normally 4–20 mA D.C.) and used for indicating, recording and controlling purposes.

Vibration and displacement

A stationary vibration monitoring system is usually installed on turbines. Such a system generally consists of accelerometers or proximity sensors located radially in each bearing and axially on the end of the shaft or the thrust collar. Two sensors positioned at right angles are typically used in

bearings. Electronic monitoring equipment is used to measure the acceleration or displacement that occurs at each monitoring point. The monitoring equipment generally incorporates an 'alarm' setting which is intended to warn the operator of an impending problem, and a 'trip' setting, which intended to shut the machine down. In many instances, a vibration-initiated shutdown can prevent major damage in situations in which, without prompt action, equipment could be lost.

Displacement, velocity, acceleration and vibration are the terms that are related to each other by time. Vibration can be defined in terms of displacement, velocity, or acceleration. If the sensor is mounted on to the surface of the vibrating object, it will provide a reading of absolute vibration relative to a fixed point in space. If the mass of the rotating object and therefore its resonant frequency would be affected by physically attaching the sensor to it, a hole can be drilled through the housing of the bearings and a non-contacting proximity probe can detect the relative motion between shaft and bearing. The electronics associated with the sensor can be integral or remote. Relative accelerometers, absolute (or seismic) accelerometers, variable-reluctance accelerometers, eddy current proximity vibration pick up and mechanical-magnetic vibration sensors are some of the commonly available sensors for vibration and displacement measurements.

Bearing temperature

Bearing temperature is an indication to check whether the lubrication is occurring. It is also a way of detecting deterioration in bearings before complete mechanical failure. Mechanical wear accelerates as a result of improper lubrication or because of mechanical stresses that cause deformation of the bearing component parts. In either case, the bearing begins to dissipate abnormally large amounts of energy, which in turn results in heating. Consequently, a sudden rise in bearing temperature is generally an indication of incipient failure. It is important to discontinue operation of the machine quickly when a potential bearing failure is detected. Some turbine designs maintain a very small clearance between stationary and rotating parts. If the bearing deforms, it may mean the total destruction of the machine.

Platinum resistance temperature detectors (RTDs), called in short as Pt100 thermometers, are inserted in the bearing casing to touch the outer ring of the bearing. The same arrangement is done for turbine as well as alternator bearings. The signals are transmitted with the help of RTD-mA transmitters for indication and recording in the control room. Parallel indicators are also provided in the local panel for operators' guidance. Also mercury-in-glass thermometers are installed for local indications near the bearings themselves. As this measurement is very important, annunciation contacts are generated both from local mercury-in-glass thermometers and from indicators of RTDs. The 'alarm' and 'trip' contacts are normally generated and interlocked with other safety systems.

Lube oil parameters

Lubrication oil is being used for cooling the bearings of turbine and alternator. Four important parameters to be measured in connection with lube oil are pressure, flow, temperature and level. Pressure measurement is carried out with the help of pressure transmitter for remote indication and with Bourdon tube pressure gage for local indication. Flow measurement is carried out with orifice cum differential pressure transmitter arrangement or with rotameter. In case of rotameter with transmitter, the purpose of both local and remote indication is served. Temperature measurement is carried out with RTD as sensor and a transmitter for remote indication and control.

Mercury in glass thermometers or gas-filled thermometers are used for local indication purpose. Lubrication oil tank level is measured with differential pressure transmitter for remote transmission and gage glass for local indication. Annunciation contacts are generated with the help of remote indicators and/or with local indicators.

Casing or shell temperatures

The turbine casing or shell temperatures are another group of important turbine parameters. Casing or shell is the principal stationery element which surrounds the rotor and holds, internally, any nozzles, blades and diaphragms that may be necessary to control the path and physical state of the expanding steam. It is shaped to become the mainframe and support of the assembled turbine. It is essential to measure steam inlet temperature and the differential temperature between steam and the casing (shell) in order to avoid the excessive temperature differences within the steel casings of turbines during starting and shutting down. Quick starting and loading produces large gradients of temperature and if they are too large, excessive thermal strains, leading to cracks in the turbine casing, will be produced.

The casing temperatures are measured at different locations, may be up to 6 locations. The holes are drilled to accommodate sensors, which are normally type-J thermocouples. After the sensors are put and extension cables (compensating leads) taken out, they are grouped together and recorded in a multipoint recorder so that the comparison between temperatures is easily possible.

5.3.3 Electrical Parameters

Voltage, current, power, reactive power, energy, frequency and power factor are the major parameters measured under this category. As they are all connected with generator which is coupled with turbine, we shall discuss about them very briefly here.

Voltage

The potential difference, electromotive force (emf) and pressure of an electrical circuit are other names for voltage. It is measured with the help of voltmeter. Voltmeters are standard items on switchboards and control panels. They are basically single-circuit elements; therefore when three phases are to be indicated, either three instruments are used or one with a multipoint switch. The voltmeter is connected across the line and is a high impedance one. The voltmeter ranges can be varied with high value resistors connected in series. Such resistors are called *voltmeter multipliers*. For very high voltages, potential transformers (PT) are connected to the main lines and the voltmeters connected to their secondaries. Current transformer (CT) , which is used for measuring large current, and the potential transformer (PT) are called in general *instrument transformers*. Voltmeters are normally of moving iron types. Moving coil meters can also be used, but in conjunction with rectifiers.

Current

The quantity of electrical current flowing through a circuit is measured with the help of ammeter. The ammeter is connected in series with the line and is a low impedance one. Ammeters are accommodated to various ranges with small value resistances connected in parallel to the instruments. For very large current measurements, current transformers are connected to the main

lines and the instruments connected to their secondaries. Normally the powerline itself is considered as primary windings of the current transformer. Their secondary windings are practically short-circuited by the measuring ammeters. Current transformers have the function to convert the current to be measured into a conveniently measurable secondary current while preserving proportionality of values and phases. Ammeters are almost identical to voltmeters, but for their input impedances and mode of connections. Common ammeter and voltmeter connections are shown in Figure 5.7 for low current and low voltage applications and in Figure 5.8 for large current and high voltage applications.

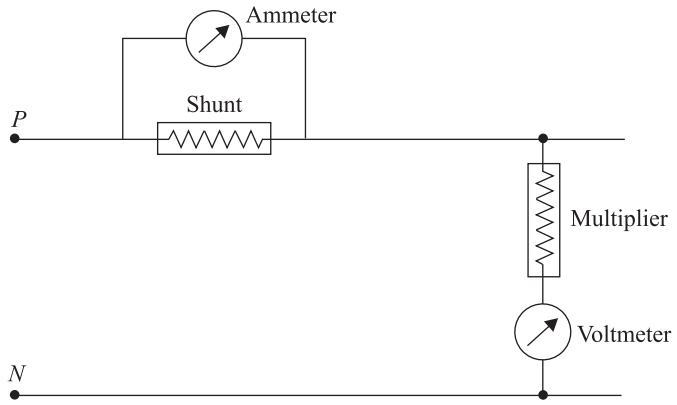


Figure 5.7 Ammeter and voltmeter connections (for low values).

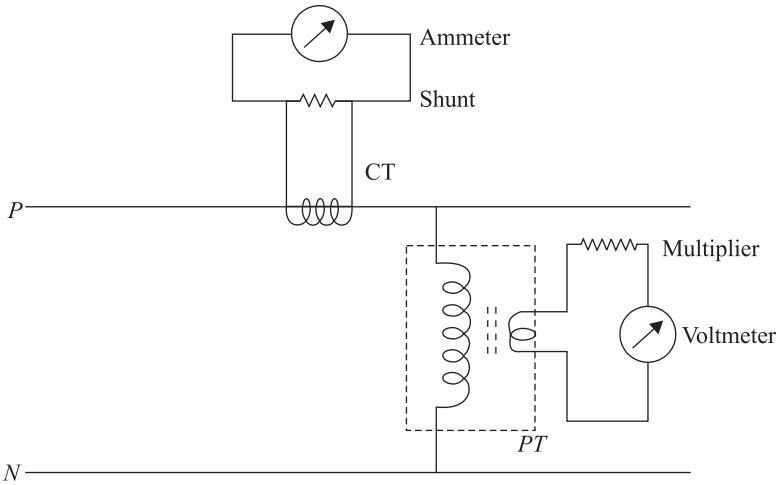


Figure 5.8 Ammeter and voltmeter connections with instrument transformers (for high values).

Power (*active*)

The power of a direct current (always active) can be found from one ammeter and one voltmeter. Both readings can be multiplied to get the power. Electrodynamic wattmeter with voltage coil and current coil can be used directly to measure d.c. power.

The active power of an alternating current circuit is given by $VI \cos \phi$ where $\cos \phi$ is called the power factor and ϕ is the phase angle between the voltage and the current. V and I are RMS values of voltage and current respectively. Single phase a.c. power can be measured by connecting a wattmeter as shown in Figure 5.9.

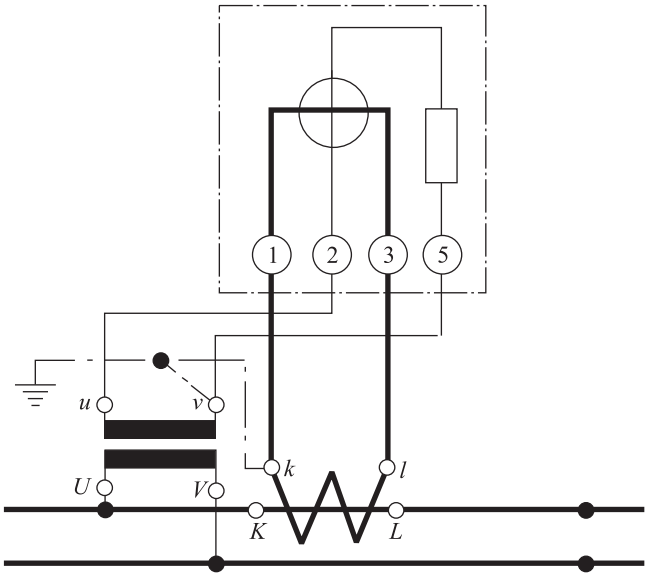


Figure 5.9 Measuring active power of single-phase ac.

Instrument transformers are connected in such a way that voltage path is connected ahead of current path and the secondaries of both transformers are connected to a common earth for safety reasons.

The active power for a three-phase system is the total of the three components. It is given by,

$$P = 3V_P \text{ I} \cos \phi \text{ for star connection}$$

$$P = \sqrt{3}\, V_L I \cos \phi \text{ for delta connection}$$

where

V_P = Phase to neutral voltage

V_L = Line to line voltage

I = Load current in a balanced condition

P = Total power

The most accurate method uses three wattmeters whose indications are added, or else a three-system wattmeter with mechanical adder having a common shaft or ribbon coupling. Some of the common methods used in power plants are briefly explained in the following pages. The instrument transformers are not shown in the sketches for simplicity sake.

Three-wattmeter method (Three-phase three-wire system): Figure 5.10 exhibits the three-wattmeter method.

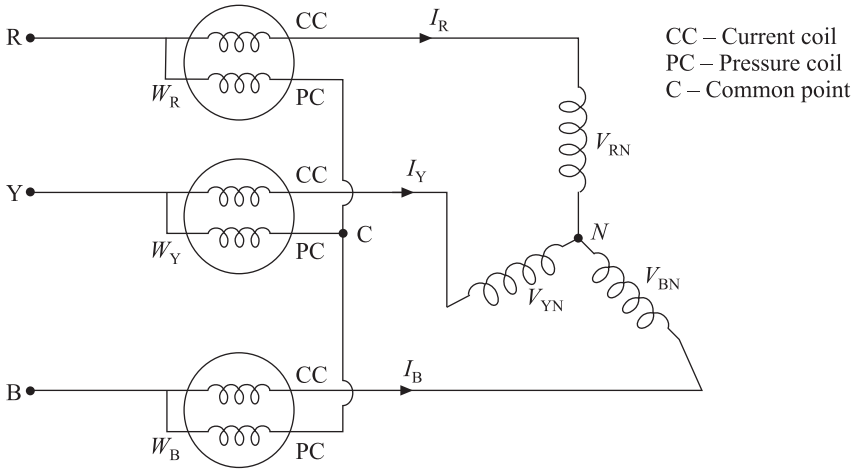


Figure 5.10 Three-wattmeter method three-phase three-wire system.

$$W_R + W_Y + W_B = V_{RC} \times I_R + V_{YC} \times I_Y + V_{BC} \times I_B \text{ and can be proved}$$
$$= V_{RN} \times I_R + V_{YN} \times I_Y + V_{BN} \times I_B = P_R + P_Y + P_B$$
$$= \text{Total power}$$

It is observed that sum of the three individual wattmeter readings ($W_R + W_Y + W_B$) indicate the total power consumed by the load ($P_R + P_Y + P_B$).

Three-wattmeter method (Three-phase four-wire system): Figure 5.11 shows the three-wattmeter (three-phase four-wire system) connections.

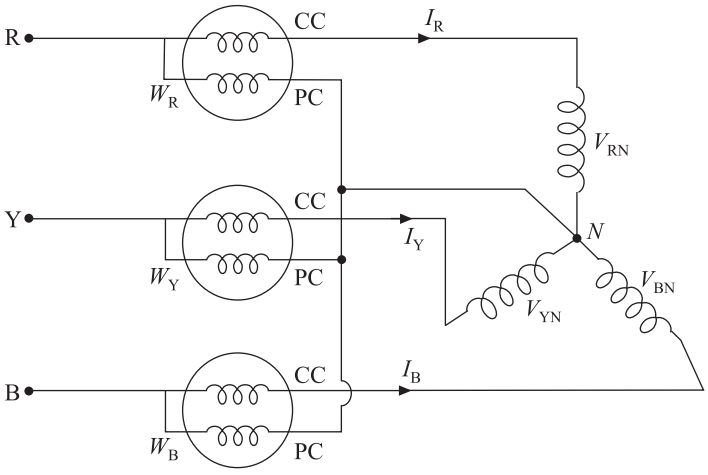


Figure 5.11 Three-wattmeter method–three phase four-wire system.

$$W_R + W_Y + W_B = V_{RN} \times I_R + V_{YN} \times I_Y + V_{BN} \times I_B$$
$$= P_R + P_Y + P_B$$

Hence, summation of the three wattmeters' readings display the total power consumed by the load.

Two-wattmeter method: This is most commonly used method for measuring three-phase power. It is useful both for balanced and unbalanced loads. Sum of the two watt-meter readings will be equal to the total power consumed as given below: For star connected load Refer to Figure 5.12.

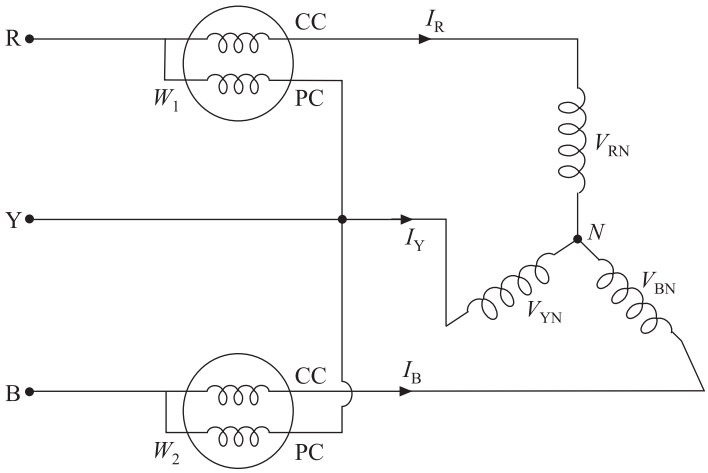


Figure 5.12 Two-wattmeter method–star-connected load.

Power consumed by the load $P = V_{RN} \times I_R + V_{YN} I_Y + V_{BN} I_B$

Summation of wattmeter readings = $W_1 + W_2$

$$= (V_{RN} - V_{YN}) I_R + (V_{BN} - V_{YN}) I_B$$
$$= V_{RN} I_R + V_{BN} I_B + V_{YN} (-I_R - I_B)$$

We know by Kirchhoff's Law $I_R + I_B + I_Y = 0$, $\therefore -I_R - I_B = I_Y$

$$\therefore \quad W_1 + W_2 = V_{RN} I_R + V_{YN} I_Y + V_{BN} I_B = P$$

For delta connected load Refer to Figure 5.13.

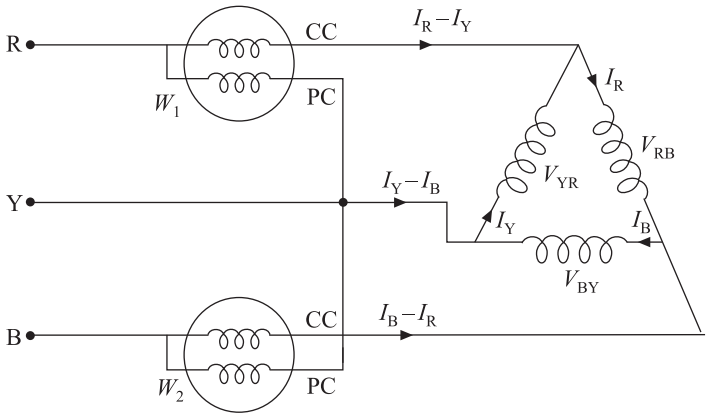


Figure 5.13 Two-wattmeter method–delta-connected load.

$$P = V_{RB} I_R + V_{YR} I_Y + V_{BY} I_B$$

$$W_1 + W_2 = -V_{YR} \times (I_R - I_Y) + V_{BY} \times (I_B - I_R) = V_{RB} I_R + V_{YR} I_Y + V_{BY} I_B = P$$
$$(\because V_{YR} + V_{BY} + V_{RB} = 0)$$

It can be proved that $W_1 + W_2 = 3\ VI \cos\phi$ (total power) and $W_1 - W_2 = \sqrt{3}\ VI\ \sin\phi$ and hence

$$\tan\phi = \sqrt{3}\,\frac{W_1 - W_2}{W_1 + W_2};\ \text{Power factor}\ \cos\phi = \cos\left[\tan^{-1}\left(\sqrt{3}\,\frac{W_1 - W_2}{W_1 + W_2}\right)\right]$$

Reactive power

If V and I are the RMS values of the voltage and current in a single-phase ac circuit and ϕ is the phase angle between them, then the active power in the circuit is $VI \cos\phi$. The active power is obtained by multiplying the voltage by the component of current which is in same phase with the voltage (i.e. Icos ϕ). The component of current which is 90° out of phase with voltage (i.e. I sin ϕ) is called the *reactive component of current* and the product $VI \sin\phi$ is called the *reactive power*. Measurement of reactive power along with active power, is sometimes important. The phase angle ϕ of the circuit can be obtained from the ratio of (reactive power) to (active power).

$$\frac{\text{Reactive power}}{\text{Active power}} = \frac{VI \sin\phi}{VI \cos\phi} = \tan\phi$$

$$\therefore \qquad \phi = \tan^{-1}\left(\frac{\text{Reactive power}}{\text{Active power}}\right)$$

The same wattmeter that is used for measuring active power can be used for measuring reactive power also with slight modifications in the connections. Observing the fact that $\sin\phi = \cos(90° - \phi)$, the wattmeter may be so connected that the current coil carries the load current and the voltage coil should have a voltage that is 90º out of phase with the actual voltage of the circuit. Under these circumstances, the wattmeter will read $VI \cos(90 - \phi)$or $VI \sin\phi$. The unit for reactive power is 'Reactive volt-ampere' or simply 'VAR'.

For single phase measurements, the pressure coil circuit may be made to behave as large inductive by inclusion of external inductor in series with it. This will cause the pressure coil current to lag behind the voltage by 90º, and thus the wattmeter will read,

$$VI \cos(90 - \phi) = VI \sin\phi = \text{Reactive power.}$$

For measurement of reactive power in a circuit with balanced three-phase load, a single wattmeter may be used with suitable connections as shown in Figure 5.14 and the corresponding phasor diagram is drawn in Figure 5.15.

The wattmeter will read,

$$V_{RY} \times I_B \times \cos(90° + \phi) = \sqrt{3}\ VI \cos(90° + \phi)$$
$$= -\sqrt{3}\ VI \sin\phi = W_R$$

where

V = Phase rms voltage,

I = Phase current

$$\therefore \quad \text{Total reactive power} = 3VI \sin\phi = -\sqrt{3}\,(-\sqrt{3}\,VI \sin\phi)$$

$$= -\sqrt{3}\,W_R$$

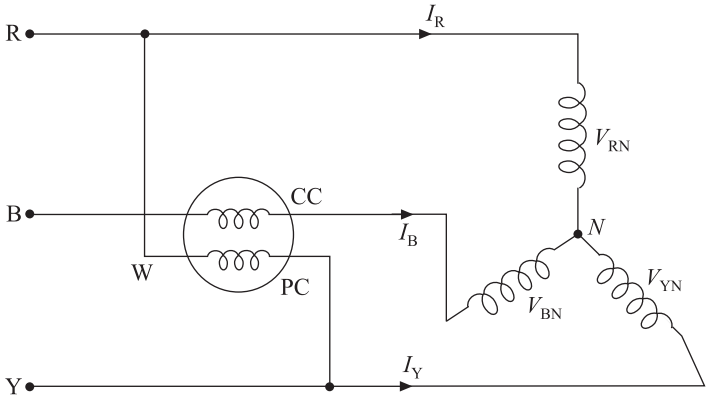


Figure 5.14 Reactive power measurement–balanced load.

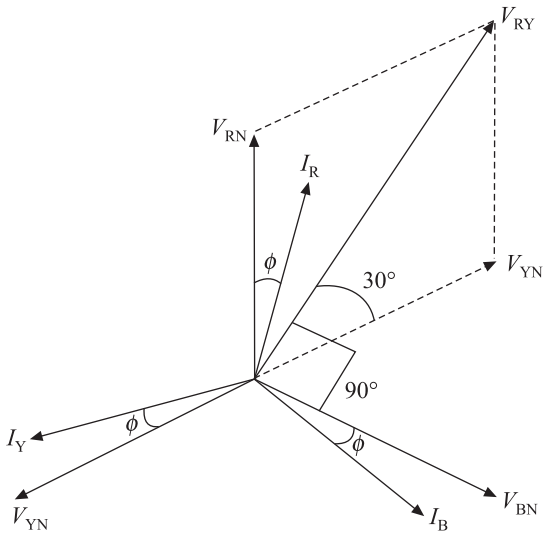


Figure 5.15 Phasor diagram for reactive power measurement.

Energy

Energy is the total power generated (or consumed) over a time interval.

$$\text{Energy} = \text{Power} \times \text{Time}$$

Generally the process of measurement of energy is same as that for measurement of power except for the fact that the instrument used should not merely measure power, but also take into account the time interval during which the power is being supplied. The unit of energy can be expressed in

terms of watt-hour or kilowatt hour (kWh). The kWh is defined as the energy supplied (or consumed) at an average rate of 1 kilowatt for one hour. In commercial metering 1 kWh is called 1 unit of energy.

Energy meters used for measurement of energy have moving systems that revolves continuously unlike in indicating instruments where it deflects only through a fraction of a revolution. In energy meters, the speed of revolution is proportional to the power and the total number of revolutions made by the meter moving system over given period of time is proportional to the energy.

Induction type instruments are most commonly used as energy meters. Such meters have lower friction and higher torque/weight ratio. They are inexpensive, yet reasonably accurate. Constructional details of an induction type single phase energy meter are shown schematically in Figure 5.16. The operating system consists of two electromagnets. Current coil is wound on series magnet and the pressure coil on shunt magnet. Shading bands made of copper are used to bring the flux produced by shunt magnet exactly in quadrature with the applied voltage. The moving system consists of a light aluminum disc mounted on a spindle. The disc is placed in the space between the series and shunt magnets. The disc is so positioned that it intersects the flux produced by both the magnets. The deflecting torque on the disc is produced by interaction between these fluxes and the eddy current they induce in the disc. As there is no control spring, continuous rotation is possible. The braking system (not shown in Figure 5.16) consists of a permanent magnet positioned near the edge of the aluminum disc whose position is adjustable. When the braking torque becomes equal to the operating torque, the disc rotates at a steady speed. A registering system consisting of a train of reduction gears makes the counting in numerical value possible.

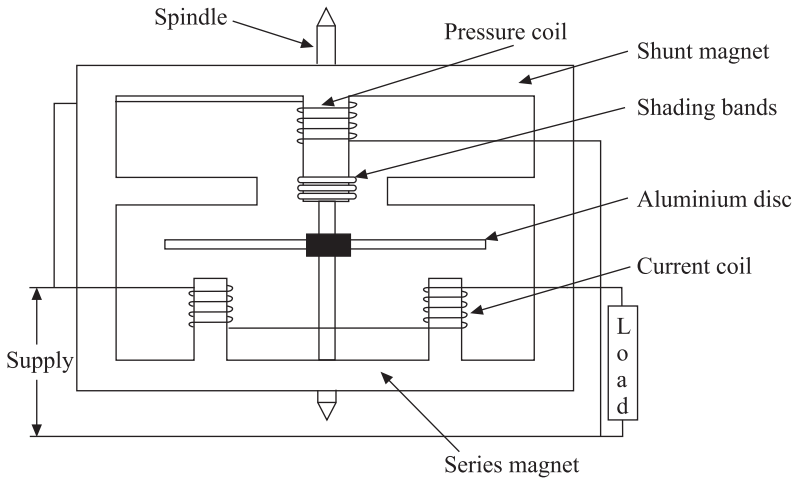


Figure 5.16 Constructional details of induction type single-phase energy meter.

Frequency

Frequency meters indicate the generated power frequency directly, and are thus more convenient for most practical purposes. Four main classes of frequency meters are of importance to us.

1. **Frequency meters depending for their operation upon the phenomenon of mechanical resonance:** Based on this principle 'vibrating reed frequency meter' is constructed. It consists mainly of a number of thin steel strips called 'reeds', arranged along side, and close to, an electromagnet. The electromagnet is laminated and its winding is connected, in series with a resistance, across the supply whose frequency is to be measured, the external connection being thus the same as those of a voltmeter. The reeds may look identical, but are made with slight differences so that their natural frequencies are different. They are arranged in ascending order of frequency normally starting from 47 cycles per second up to 53 cycles per second with every reed covering half cycles per second. Thus the natural frequency of the first reed is 47 cycles per second; of the one next to it 47½ cycles per second; of the next 48 and so on. When the meter is in use the magnetism of the electromagnet alternates with the frequency of the supply, and exerts an attracting force upon the reeds. The one whose natural frequency is matching with the supply frequency will vibrate appreciably showing the supply frequency. The flags at the top of the reeds are painted with the corresponding frequency so that one can read directly the frequency by observing the reed which is vibrating most. A great advantage of this type of meter is that its indications are independent of the applied voltage and waveforms.
2. **Frequency meters employing electrical resonance:** The frequency meter consists of a magnetizing coil, which is connected across the supply circuit, and therefore carries a current of the frequency to be measured, wound on one end of a laminated iron core. Another end of the core carries a pivoted moving coil with pointer attached to it. The terminals of this coil are connected to a suitable capacitor *C*.

   Refer to Figure 5.17 for its operation. The capacitive reactance $\frac{1}{\omega C}\left(\text{or } \frac{1}{2\pi fC}\right)$ is constant for any given frequency. The inductive reactance ωL (or $2\pi fL$) depends upon the position of the pivoted coil on the core. The nearer this coil approaches the magnetizing coil the greater its inductance. The pivoted coil is pulled towards the magnetizing coil, therefore, until $\omega L = \frac{1}{\omega C}$ when the torque is zero. Obviously the circuit of the moving coil is in resonance when the torque is zero. The value of the capacitor *C* is so chosen that the pivoted coil takes up a convenient mean position when the frequency is at normal value. If the frequency increases, the capacitance reactance $\frac{1}{\omega C}$ decreases, and the coil moves off the core so that its inductance is reduced to the point when ωL again equals $\frac{1}{\omega C}$. The coil moves further on to the core if the frequency falls. The pointer attached to the pivot can be made to read the frequency on a dial accordingly.

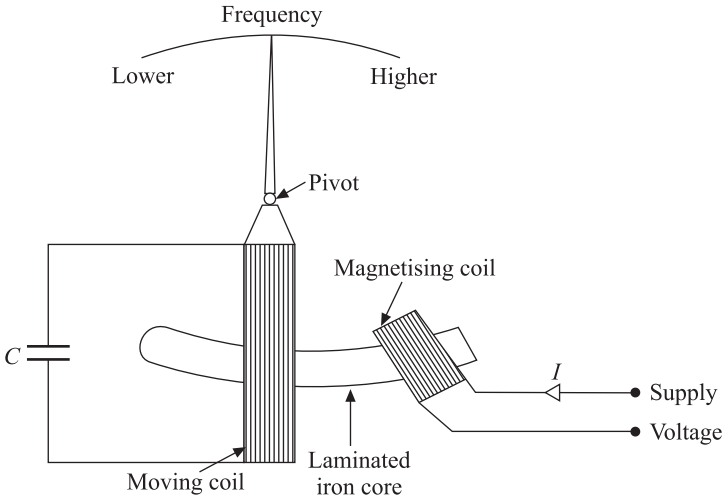


Figure 5.17 Electrical resonance frequency meter.

3. **Frequency meters whose action depends upon the variation of impedance of an inductive circuit with frequency:** This frequency meter is an moving-iron instrument whose action depends on the variation in current distribution between two parallel circuits—one inductive and the other non inductive—when the frequency changes. The construction and internal connections are shown in Figure 5.18. There are two fixed coils, *A* and *B*, each in two equal parts. These coils are fixed so that their magnetic axes are perpendicular and at their centre is a pivoted soft-iron needle. The spindle bearing the needle also carries a pointer and damping vanes, but there is no controlling device.

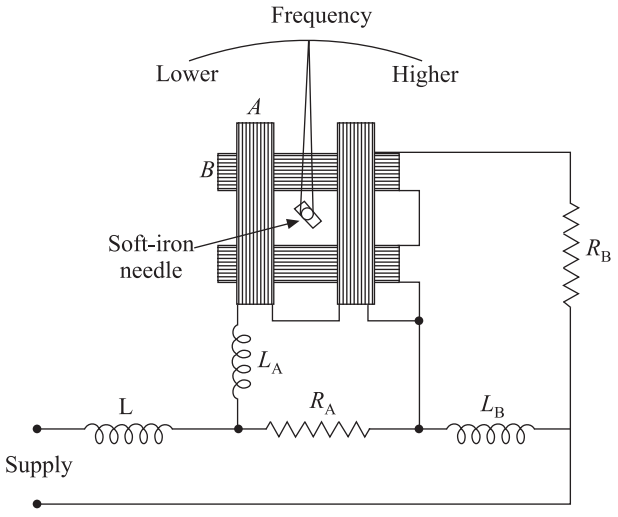


Figure 5.18 Frequency meter with inductance variation.

Coil *A* is connected, in series with an inductance L_A, across a non-inductive resistance R_A, and coil *B* is connected, in series with a resistance R_B, across an inductance L_B as

shown. The inductance L is for the purpose of damping out harmonics. The soft iron needle takes up a definite position depending upon the currents through the coils *A* and *B*. If the frequency is increased, the current through coil *A* is reduced, since the reactance of L_A increases while the voltage drop across R_A remains the same. On the other hand, the current in coil *B* increases. The total effect is, therefore that of turning the pivoted needle so that it lies more nearly parallel to the axis of coil *B*. Decrease in frequency obviously has the opposite effect, and these variations of frequency are followed by the pointer, as shown in Figure 5.18.

Frequency meter based on digital principle: Digital frequency meters are used nowadays in most of the modern power plants. Alternating current wave form, i.e. sinusoidal wave form is first converted into square wave form train and counted using a digital counter for a fixed period of time to get frequency. The simplified schematic circuit is shown in Figure 5.19.

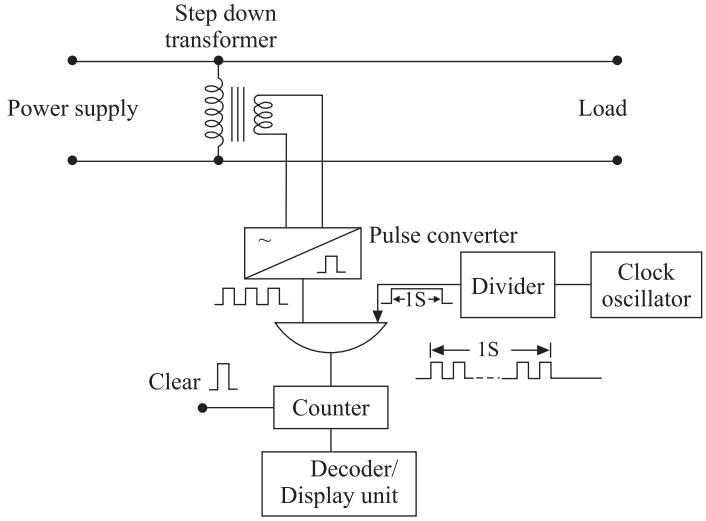


Figure 5.19 Digital frequency meter.

The meter operates on the principle of gating the unknown input signal into the counter for a predetermined time. In our case, if line frequency is 50 cycles per second, the number of pulses coming out of the 'AND' gate for a second will be 50. The counter counts it as 50 and is displayed as 50 cycles per second.

Power factor

Power factor meters indicate the power factor of a circuit directly, as distinct from instruments from whose readings the power factor may be obtained by dividing the watts supplied, by the volt-amperes in the circuit using the formula given inside the bracket.

$$\left[\frac{\text{Wattmeter reading}}{\text{Varmeter reading}} = \frac{VI\cos\phi}{VI\sin\phi} = \frac{1}{\tan\phi}\right]$$

Power factor meters—like wattmeters—have a current circuit and a pressure circuit. The former carries the current in the circuit whose power factor is to be measured. The pressure

circuit is usually split into two parallel paths – one inductive and one non-inductive-and the deflection of the instrument depends upon the phase differences between the main current and the currents in the two branches of the pressure circuit, i.e. upon the power factor of the circuit. One such dynamometer type single phase power factor meter is shown in Figure 5.20.

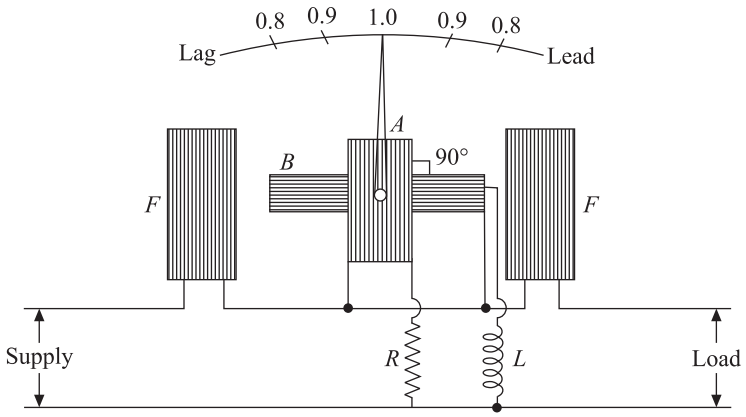


Figure 5.20 Single-phase dynamometer type power factor meter.

Figure 5.21 shows the connections of a three-phase power factor meter, the readings of which are correct only when the load is balanced. In this instrument the two moving coils are fixed with

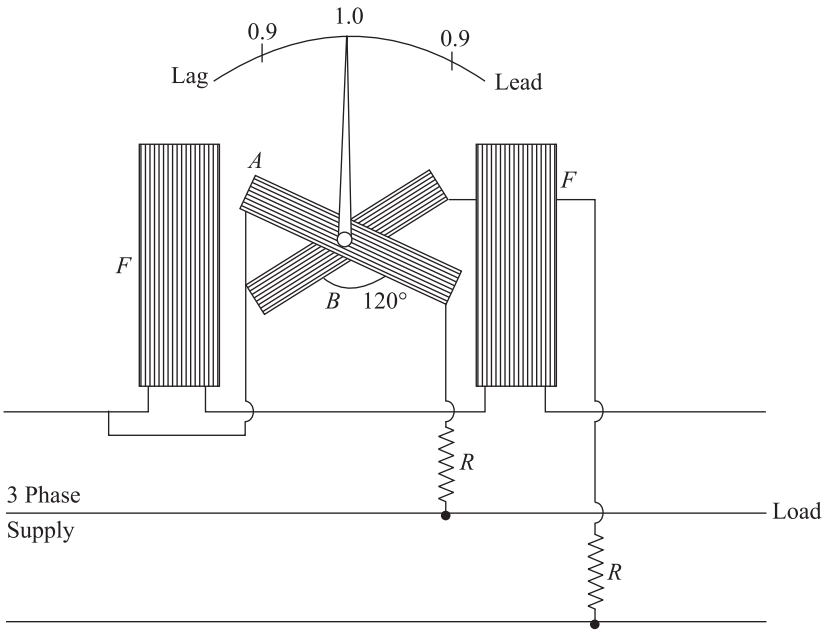


Figure 5.21 Three-phase dynamometer power factor meter for balanced load.

their planes 120º apart, and are connected across two different phases of the supply circuit, the fixed coils being connected in the third phase and carrying current in the line. There is now no necessity for phase-splitting by artificial means, since the required phase displacement between the currents in the two moving coils can be obtained from the supply itself as shown. Provided the two moving coils are 120º apart, the angle through which the pointer is deflected from the unity power-factor position is equal to the phase-angle of the circuit. This three-phase instrument gives indications which are independent of frequency and wave form, since the currents in the two moving coils are both affected in the same way by any change of frequency.

5.4 TURBINE CONTROL SYSTEM

The turbine control system can be broadly classified into two systems, namely, 'safety control systems' and 'process control systems'. The purpose of safety control system is to take care of the safety of men and machine. It is intended to eliminate or at least minimize the activities which can cause damage to the equipment and become hazardous to persons working in the power plant. Process control system is to take care of process operations as per the application requirement.

5.4.1 Safety Control Systems

The turbine shut off valve acts as the master safety element in turbine safety control system. It is a quick shut off valve operated by a solenoid. While starting the turbine, the number of interlocks provided for safety purpose should satisfy the conditions for starting. Then only the shut off valve can be opened and steam allowed to go through governor to the turbine in proper way. The shut off valve will close if any emergency condition appears during normal running of the turbine. High bearing temperatures, lube oil failure, overspeed, extraordinary vibration and displacement are the causes for which the shut off valve has to be closed. The overall safety monitoring system for a steam turbine is shown in Figure 5.22. In modern turbines many more safety controls are added. Also hooked up are safety parameters from alternator side. Low frequency, high voltage, feeder faults etc are also hooked up with tripping circuit.

The measurements covered by the turbine safety control system include,

1. Pedestal vibration
2. Shaft vibration
3. Eccentricity
4. Rotor and casing movement
5. Metal temperatures
6. Speed

Pedestal vibration

Vibration transducers provide the signals for routine monitoring in the control room and give an indication plus warning to ensure that the plant is never operated in conditions severe enough to cause damage.

In addition to the indications, required for normal operation, facilities are usually available for analysis of the vibration signal to provide information relating to plant condition. The analysis can show, for example, whether the shaft is cracked and over a period, how the crack is

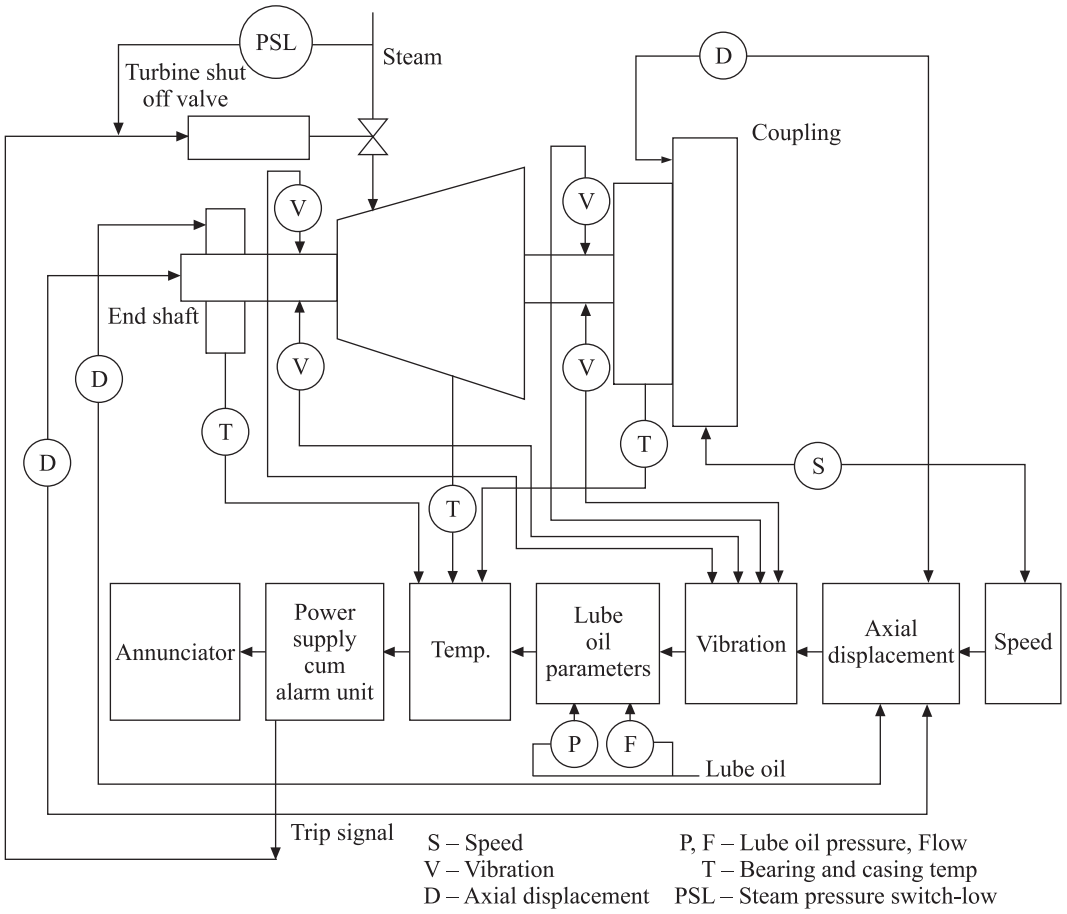


Figure 5.22 Turbine safety monitoring system.

developing. In this respect comparison of the turbine rundown signatures over several shutdowns is useful.

In some power stations, permanent equipment is used to provide data every time the speed of the machine is reduced so that the vibration spectra can be kept under constant review, and incipient failures detected and monitored.

Turbine pedestal vibration is characterized by three basic quantities, amplitude, frequency and phase. In this context, amplitude refers to the level of vibration and can be represented by displacement, velocity (or) acceleration.

Vibration displacement: Displacement is the total distance the vibrating part moves in a given direction and is measured in units of length; micrometers μm (10^{-6} m) are convenient units.

Velocity of vibration: Velocity of vibration is the speed at which the part is moving at any instant during the vibration cycle. Velocity during one complete cycle of sinusoidal motion varies from zero to maximum or peak. The value normally adopted for turbine pedestal vibration measurement is the RMS velocity, the units being mm/s.

Acceleration due to vibration: Acceleration is the rate of change of vibration velocity at any instant during the vibration cycle. The RMS value in mm/s^2 is normally displayed by vibration measuring instruments.

Shaft vibration

Steam turbines have several modes of vibration in the operating speed range and it has been shown that their responses to imbalance, thermal bends, rubs and unloading of bearings may be more clearly observed by measurements of shaft movements within the bearings rather than by vibration of the pedestal. Shaft vibration is defined as the dynamic movement of the shaft around the eccentricity locus. Shaft vibration measurements are used for a number of purposes, ranging from routine operational monitoring to specialist experimental investigation of changes in vibrational behaviour of the plant and monitoring of radial clearances.

Eccentricity

Eccentricity is defined as the out of centre excursion of the axis of rotation of the shaft. It is normally measured as the diameter of the locus traced out by the shaft centre.

Rotor and casing movement and expansion

The movement and expansion of individual casings has to be measured to ensure that the alignment between pedestals is maintained within acceptable limits.

The type of transducers used in most operational units for the measurement of shaft vibration and eccentricity are noncontacting proximity devices. The system consists of a transducer, connecting cable and an electronic processing unit. Figure 5.23 shows the locations of vibration, eccentricity and differential expansion monitoring system.

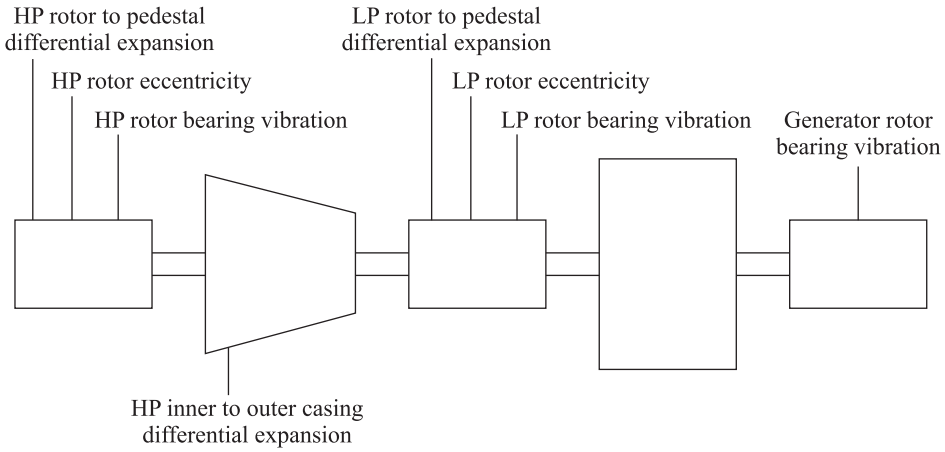

HP rotor to pedestal differential expansion
HP rotor eccentricity
HP rotor bearing vibration
LP rotor to pedestal differential expansion
LP rotor eccentricity
LP rotor bearing vibration
Generator rotor bearing vibration
HP inner to outer casing differential expansion

Figure 5.23 Location of vibration, eccentricity and differential expansion measurements.

Temperature measurements

Supervisory temperature measurements comprise casing temperatures and steam to metal temperature differences and thermal gradients.

Metal temperatures: Metal temperatures in the HP and IP cylinders are measured by means of duplex type-K thermocouples inserted into close fitting holes drilled into the steam chest or cylinder walls. The measurements are nominally taken either at the inner wall or the midwall position.

Cylinder metal temperatures: The HP and IP cylinder inlet bulk metal temperatures are important during turbine run-up and loading and have to be measured with a high degree of reliability, using retractable thermal probes in each cylinder. Four duplex type-K thermocouples are provided for each measurement, two positioned at the probe tip and two located at the inner cylinder midwall position, measuring the midwall (or) bulk temperatures. The HP cylinder measurement is usually used to supply inner wall temperature signals for automatic run-up, while the IP probe is used for indication purposes. Refer to Figure 5.24 for typical thermocouples arrangement.

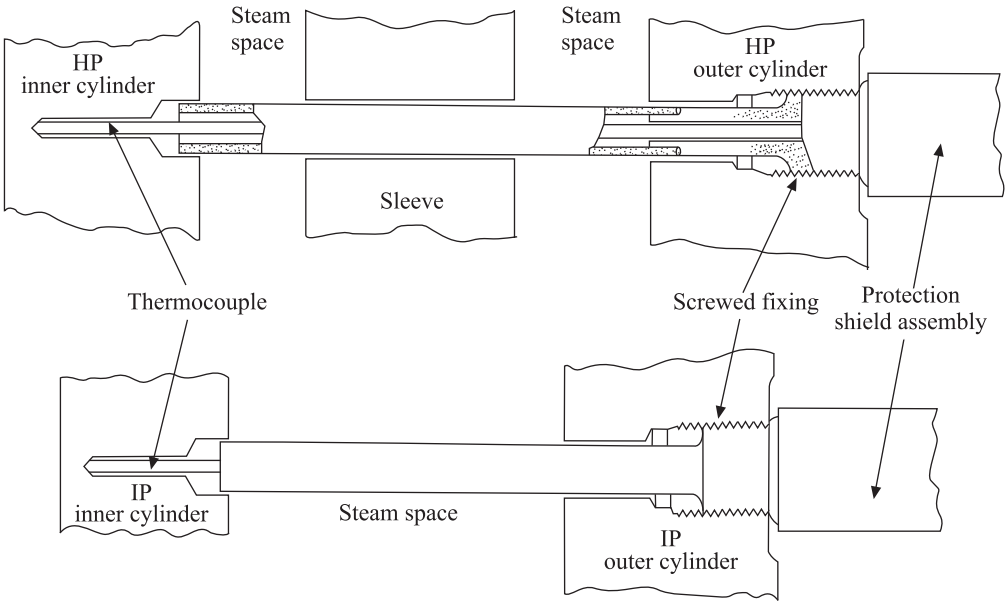


Figure 5.24 Typical thermocouple arrangement for measuring steam turbine HP and IP inner wall temperature.

Rotor temperatures: The HP and IP rotors can be subjected to high thermal stresses as a result of temperature gradients through the rotor assemblies. These conditions arise during start-up when high temperature steam flows over relatively cool rotors. Several methods have been adopted to predict the temperature gradient during turbine run-up. Some rely on heat transfer equations written into the computer software, others make use of measurements taken in the HP and IP steam pipes located in positions within the pipe work in such a way that their response over short periods is the same as that of the rotor.

Metal temperatures are displayed as individual temperatures or differential temperatures from combinations of individual or average temperatures.

Speed measurements

The tachogenerator speed measurement system produces a voltage and frequency proportional to shaft speed. Two types are in common use, one using the level of output voltage which is directly proportional to speed, the other using the frequency of the output waveform.

Using the tachogenerator in its voltage mode, the signal may be rectified and smoothened to provide a DC signal proportional to speed.

Toothed-wheel and probe: Of the variety of speed detection methods available, the toothed-wheel and magnetic probe is probably the most usual choice, which is shown in Figure 5.25. Although this system is influenced by shaft magnetisation, the problem can be reduced by providing a disk of non-magnetic material of adequate diameter and by ensuring that sufficient ferrous material surrounds the shaft to provide an alternative low reluctance path. Further improvement can be provided by making the probe and wheel from materials with as high a saturation flux density as possible. If a permanent magnet material is employed which has a moderate level of permanent magnetism, combined with a high level of saturation density to cause remagnetisation, the probe system can be designed to operate satisfactorily in the presence of appreciable magnetic fields while the chance of demagnetization is reduced significantly.

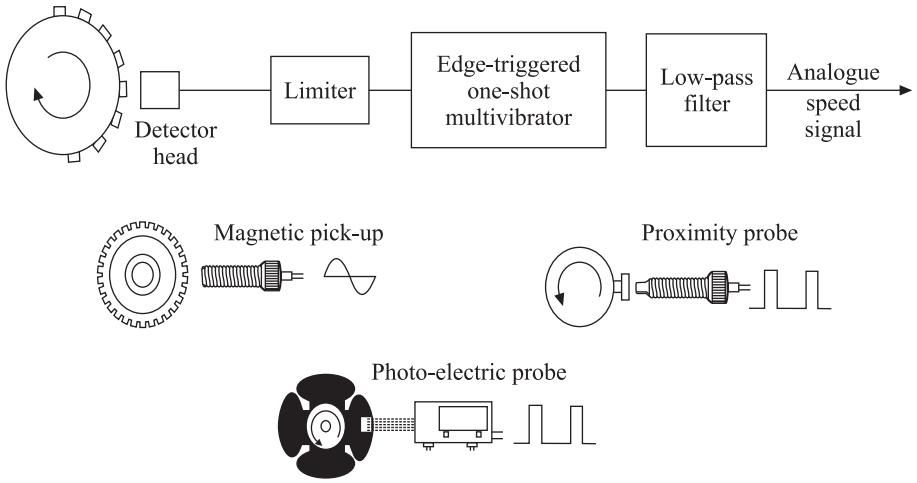


Figure 5.25 Toothed-wheel speed measuring system.

General design considerations: It is difficult to design toothed-wheel systems which will inherently produce an accurate sinusoidal output. In practice, they normally produce output pulses of which only the leading edge is significant. No information is transmitted except at the instant that the pulses occur, which needs a high pulse repetition rate, if good stability is required.

Because the change in time interval between successive pulses is a measure of shaft acceleration, it follows that a system should be chosen in which a uniform train of pulses is generated under steady speed conditions, otherwise the detection of true machine acceleration may be confused with noise induced by pulse jitter. This criterion can be used to determine the maximum useful number of teeth. In general, the angular machining accuracy of the teeth and the mounting eccentricity of the wheel on the shaft will be independent of the number of teeth.

A probe system producing substantially a square wave output is usually desirable. It must be suitable for use where a relatively large air gap exists between the probe tip and toothed-wheel, which will accommodate the varying hydrodynamic conditions in the bearings.

The overall power plant protection arrangement including boiler is shown in Figure 5.26 for clear understanding purpose.

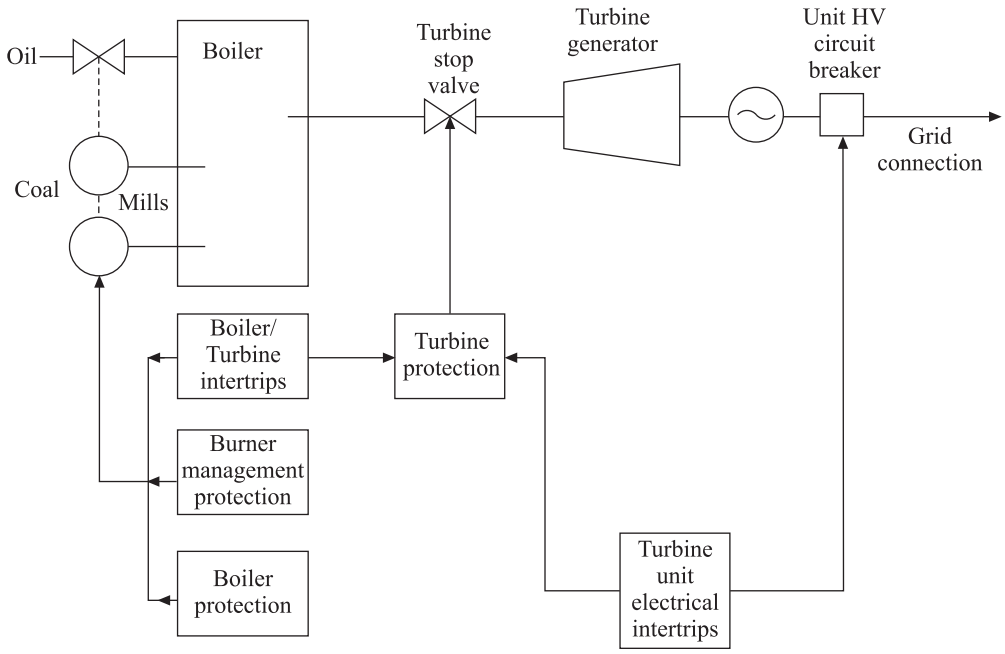


Figure 5.26 Overall power plant protection arrangement.

5.4.2 Process Control Systems

Turbine has to be operated as per the requirements of the application. In a power station application, the turbine has to be made to respond for the electrical load fluctuations. The increase in electrical load of the alternator will make the coupled turbine to decelerate. The process control system should take care of this situation by allowing more steam to compensate and allow the turbine to run at the required speed. The decrease in load will have the reverse action. Though there are a number of application methods available, we will restrict out discussions to the following four important application-oriented controls.

1. Simple condensing turbine application
2. Non-condensing turbine application
3. Extraction turbine in pressure let down application where the demand for low pressure steam (LPS) always exceeds the intermediate supply.
4. Pressure-regulating extraction turbine application when LPS demand is limited.

Turbine speed control, steam pressure control and steam flow control are the main control loops we encounter in the above applications.

Simple condensing turbine application

Turbine is supposed to act as a prime mover for some mechanical loads. In power plant applications, the turbine is to act as prime mover for an electrical generator and to run at constant speed. The required energy is supplied from a steam header, expanded in the turbine and condensed in the condenser. The speed is maintained by a governor. In electronic governor system, the speed is measured by a tachometer and compared with the set point in the controller. The controller output actuates a steam valve to manipulate the steam quantity to keep the speed always matching with set point. If the speed is varied either due to change in electrical load or due to variations in header pressure, the controller has to respond, correct it and bring the speed back to the set point. In other words, a balance has to be maintained between the energy supplied in the form of steam quantity and the work removed from the turbine's shaft in the form of electrical load. The schematic of such an application is shown in Figure 5.27.

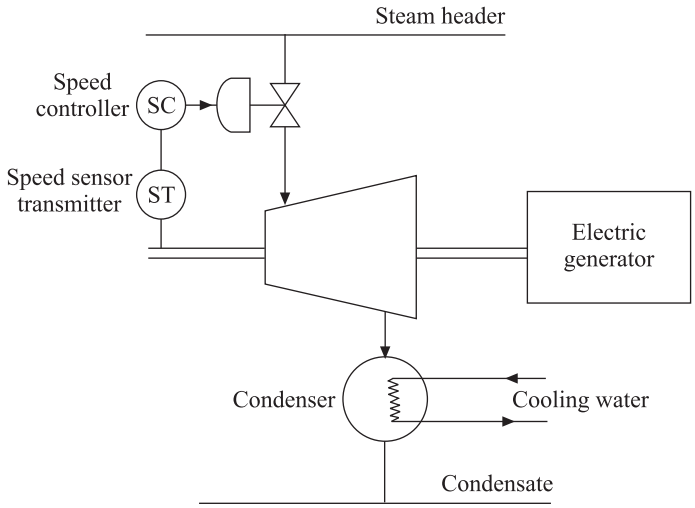


Figure 5.27 Condensing turbine application.

Non-condensing turbine application

Power plants have requirement of low-pressure steam for heating applications such as deaerators. In such cases non-condensing turbine application may work out to be more economical than condensing one. Instead of wasting energy by condensing the extracted steam with higher enthalpy can be beneficially used for low pressure applications. Figure 5.28 shows such an application which is self-explanatory.

Extraction turbine in pressure let down application

If the demand for low-pressure steam is more than the extraction steam, the extraction turbine in pressure let down application can be used. A turbine normally works in two stages. In the first stage steam is extracted for the low-pressure application. Then in the second stage the extracted steam is shared between the turbine and the low-pressure header. If the electrical load is such that the whole extracted steam or major portion of the steam has to be supplied to second stage, then

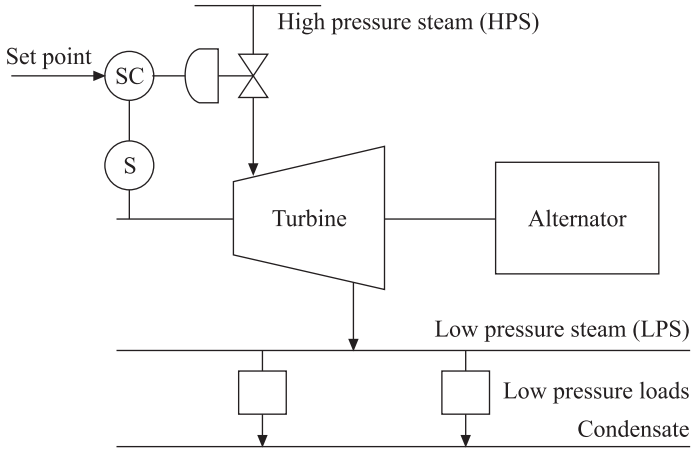


Figure 5.28 Non condensing turbine application.

the low-pressure steam header may not get enough steam. In such situations, enough steam from high pressure header is directly supplied to the low pressure header through a pressure control valve.

Figure 5.29 shows an extraction turbine in a pressure let down application. Speed control valve supplies steam to the turbine and the extraction steam is supplied to low-pressure header. The extraction valve connected as inlet to second stage remains closed. If the electrical load demand is not met in this condition, the extraction valve has to open to make up the energy. Then the low-pressure header may suffer for want of more steam which can be supplied by the pressure-control valve connected between high and low-pressure headers.

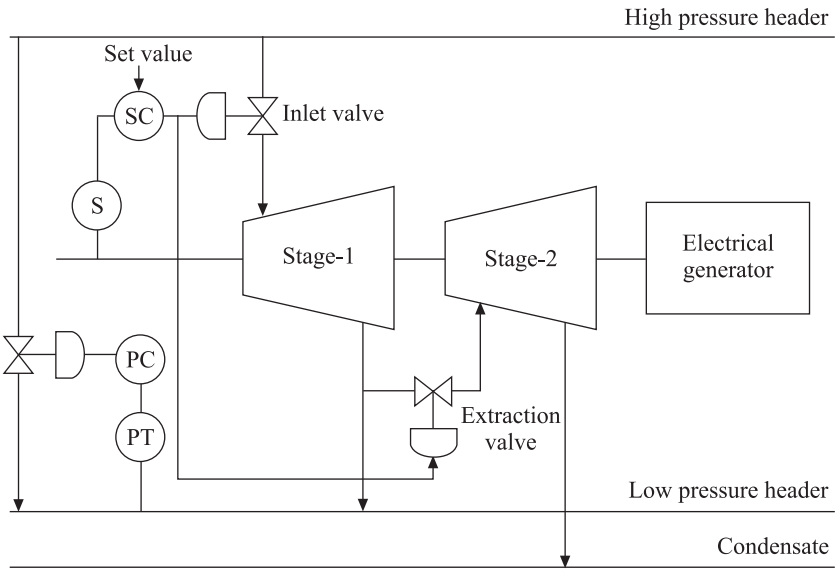


Figure 5.29 Extraction turbine in pressure let down application—LPS demand more than the intermediate supply.

Pressure-regulating extraction turbine application

In case the low-pressure steam demand is less than that of extracted steam, pressure regulating extraction turbine application is useful. The excess steam which is neither required to meet the electrical demand nor to maintain low pressure header pressure may have to be vented out. Instead the turbine may be operated in a different way. Whenever the low-pressure header is in no need of steam, the steam inlet to the turbine can be reduced. The extra energy required to the shaft may be provided by opening the extraction valve and allowing more steam to the second stage. The speed controller controls both extraction and inlet valve in a split mode.

A summing relay is added with positive input from speed controller and negative input from pressure controller as shown in Figure 5.30. As long as there is no negative input, the speed control action is similar to that explained in Figure 5.29. Whenever there is a pressure increase in the low-pressure header, there will be a increase in negative input which will cause the inlet valve to close. This will make the turbine to slow down requesting the inlet valve to open, but will be again resisted by pressure controller. Now the reverse acting speed controller output will open the extraction valve to increase the speed. An equilibrium will be achieved after some interaction.

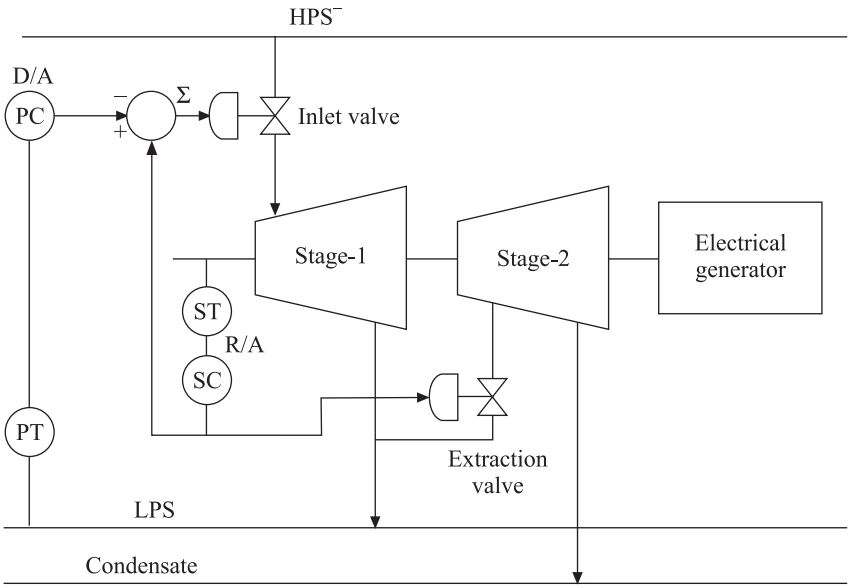


Figure 5.30 Pressure-regulating extraction turbine—LPS demand limited.

5.5 LUBRICATION FOR TURBO-ALTERNATOR

The turbo-alternator is a continuously running machine. While running, the components like main bearings, thrust bearings and reduction gears may get heated up due to turning friction. Hence a full-fledged lubrication system is needed for the turbo-alternators. Also lubrication helps cooling of journals and bearing surfaces. The lubrication oil has to flow continuously with pressure and temperature maintained. It should be free from injurious foreign matter. The aspects of lubrication system and controls are briefly discussed here.

5.5.1 Lubrication System

The block diagram of a lubrication system for a turbo-alternator is shown in Figure 5.31. Main lube oil tank is installed at an elevated plane. Though only one pump is shown in the diagram, the system will normally have a centrifugal pump attached to the turbine shaft, jet pumps to create enough pressure in the loop and auxiliary pumps, etc. A distribution box is added to divert the oil to different sections. To maintain the purity of oil, strainer and oil treater are used. Part of the oil from the tank is drained periodically from the tank to avoid contamination due to sledge formation. Oil cooler is used to bring down the temperature of the oil coming out of the turbine lubrication system so that it can be recirculated.

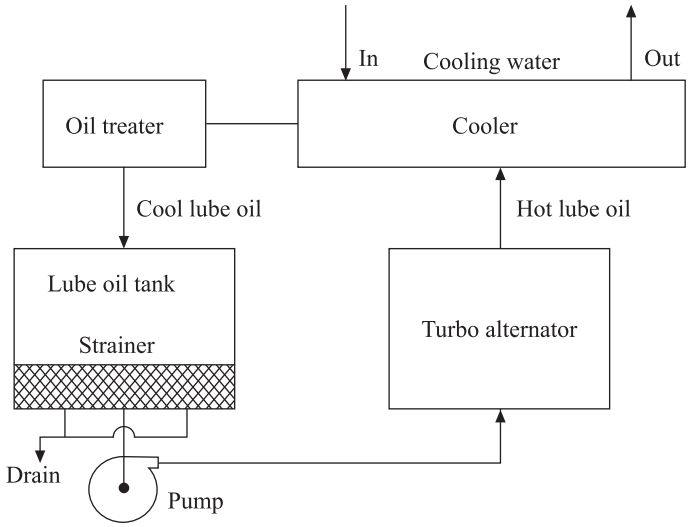


Figure 5.31 Lubrication system for turbo-alternator.

5.5.2 Controls in Lubrication System

To ensure proper lubrication oil circulation to the different sections of the turbo alternator, the following three control loops are necessary.

1. Lube oil pressure or flow rate in the line.
2. Lube oil temperature while entering from the main tank to the piping system.
3. Lube oil main tank level to ensure always the availability of enough oil quantity.

Lube oil pressure/flow control

To ensure always the lubrication oil circulation in the system, either pressure in the system or the flow rate has to be automatically controlled. One simple control system for this purpose is shown schematically in Figure 5.32. It is always possible to measure both pressure and flow rate and use one of them for controlling purpose. The other one may be used for indication and recording purpose so that the operator can have an idea about the performance of the system.

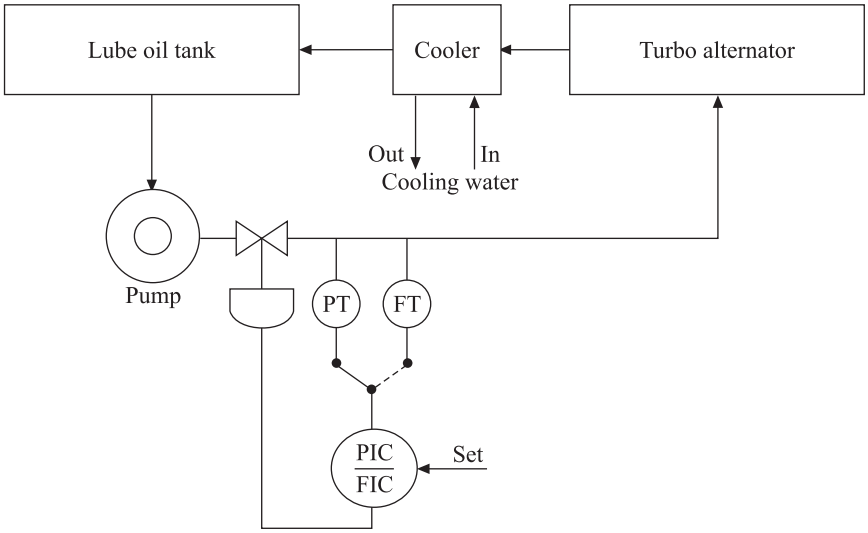


Figure 5.32 Lube oil pressure/flow control.

Lube oil temperature control

The lubrication oil while passing through bearings and gears exchange heat energy and hence it becomes heated up. It is essential to cool it to almost normal temperature so that the same oil can be recirculated. A cascade control system with cooler outlet temperature in master loop and the lube oil tank outlet temperature in slave loop is shown schematically in Figure 5.33. The cooling medium used is normally ordinary water with room temperature and is drained out. For effective cooling, any other liquid or refrigerated water can also be employed.

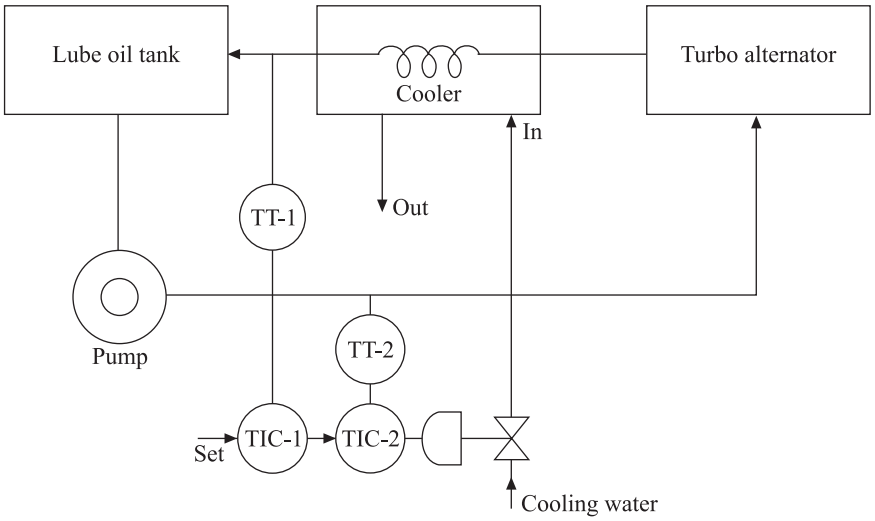


Figure 5.33 Lube oil temperature control.

Lube oil tank level control

There will be always some loss of lube oil though it is in circulation system. It has to be made up always. This make up is done automatically by employing a lube oil tank level control system. The schematic diagram shown in Figure 5.34 is self-explanatory.

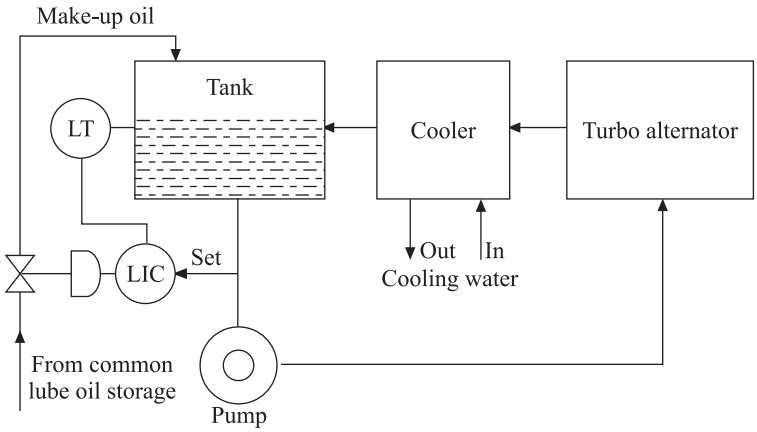


Figure 5.34 Lube oil tank level control.

5.6 TURBO-ALTERNATOR COOLING SYSTEM

There are basically three cooling systems operating in the turbo-alternator process. They are:

1. Lube oil cooling system
2. Condensate cooling system
3. Alternator/generator cooling system.

5.6.1 Lube Oil Cooling System

As we have already discussed, lube oil is used for cooling thrust and collar bearings, gears and surfaces of bearings. The heat exchanged lube oil is cooled back for further circulation as discussed in Section 5.5 (Figure 5.33).

5.6.2 Condensate Cooling System

To condense the steam exhausted from turbine for recirculation into feed water circuit, a large quantity of cooling water is required. This water is taken from the river or pond, but not treated like boiler feed water. After passing it through the condenser, it is sent to cooling tower and then recirculated. Normally no automatic control is employed here. Refer to Figure 1.22 for a simple cooling water flow circuit.

5.6.3 Alternator/Generator Cooling System

The electrical losses in the generator get converted into heat and raise the temperature of the windings, insulation and machine parts. Eddy current and hysteresis losses generated in the

iron core and copper losses (I^2R losses) generated in the windings are in general called *electrical losses*. If generated heat is not removed, the machine gets overheated, the insulation gets damaged/ becomes weak and the windings get overheated and burnt. Hence continuous cooling of the generator during the operation is very essential. Generally there are three methods of cooling.

1. Open-air cooling system
2. Closed-air cooling system
3. Hydrogen cooling system

Open-air cooling system

The open-air cooling system using atmosphere air as cooling media is used for low capacity generators of normally up to 3 MW. The air is forced to cool the rotating and stationary components. As fresh air from atmosphere is used, there is a possibility of dust and impurities entering the machine and affecting the performance of the machine.

Closed-air cooling system

Closed-air cooling system is used for large capacity generators of normally up to 100 MW. The given volume of air is circulated for cooling. The hot air coming out is cooled back in a heat exchanger with water-cooling system and is again circulated for cooling the generator. Though it is costly, the possibility of dust and impurities entering into the machine is less compared to open air cooling system.

Hydrogen cooling system

Hydrogen cooling system is used for generators of 100 MW or more capacity. The thermal properties of hydrogen like specific heat and thermal conductivity are superior to those of air and allow for reduced windage and better cooling. Windage and ventilating losses are lower because of the low density of hydrogen (one fourteenth of air). The advantages of hydrogen cooling are:

(a) Neat and clean cooling system.
(b) Reduction in noise due to lighter cooling.
(c) Requires less active material like iron and copper than air-cooled generators.
(d) Increased efficiency of the generator.
(e) The warm exiting hydrogen can be cooled in a heat exchanger with cooling water and recirculated.

There are some disadvantages of using hydrogen:

(a) Costlier system.
(b) Highly explosive when hydrogen mixes with air in certain proportion.
(c) Special maintenance tools and trained personnel are required.
(d) As hydrogen is used at about 2 bar pressure, the generator has to be made gas-tight with special seals.

Forced hydrogen cooling is used for still larger units of 500 MW and of the above capacity. Normally hydrogen filling is done after the generator is flushed with liquid CO_2 to avoid explosion.

WORKED-OUT PROBLEMS

PROBLEM 5.1 The speed of a turbine is controlled by a speed controller with a steam inlet valve. The turbine load L and steam inlet flow Q are governed by a linear relationship, i.e, $L \alpha Q$. Calculate the percentage opening of the valve at 50% of the turbine load assuming valve characteristic is governed by the relationship $Q \alpha \sqrt{h}$ where h is percentage of valve opening.

Solution:

L = Turbine load in percentage

Q = Steam flow rate through the inlet valve

h = Inlet steam valve opening in percentage

Governing relationships:

$$L \alpha Q \text{ and } Q \alpha \sqrt{h}$$

End conditions are:

When $L = 0\%$, $Q = 0$ and $h = 0\%$

When $L = 100\%$, $Q = Q_{max}$ and $h = 100\%$

$\therefore$ For 50% of load,

$$L = 50\%$$

$$Q \text{ needed} = \frac{Q_{max}}{2} \quad [\because L \alpha Q]$$

% opening $h \alpha Q^2$, i.e., $h = KQ^2$

For full load, $h_{max} = KQ_{max}^2$

$\therefore$
$$K = \frac{h_{max}}{Q_{max}^2} = \frac{100}{Q_{max}^2}$$

For 50% of load,

$$h = K\left(\frac{Q_{max}}{2}\right)^2$$

$$h = \frac{100}{(Q_{max})^2} \times \frac{(Q_{max})^2}{4} = 25\%$$

The percentage opening of the inlet valve for 50% of the turbine load is 25%

PROBLEM 5.2 At what speed the turbine should be controlled if the coupled alternator/ generator is

(a) Two-pole machine
(b) Four-pole machine

(Assume the power grid frequency as 50 cycles per second)

Solution: The equation relating to speed, number of poles and frequency is given by

$$N = \frac{120\ f}{P}$$

where

N = Speed in rpm
f = Frequency in cycles per second
P = Number of poles.

(a) Two-pole machine

$$N = \frac{120 \times 50}{2} = 3000 \text{ rpm.}$$

(b) Four-pole machine

$$N = \frac{120 \times 50}{4} = 1500 \text{ rpm.}$$

PROBLEM 5.3 Two wattmeters are connected to measure the power consumed by a three-phase unbalanced load with power factor 0.4. Total power consumed by the load, as indicated by the two wattmeters, is 30 kW. Find out the individual wattmeter readings.

Solution: If W_1 and W_2 are the two individual wattmeter readings, then

$$W_1 + W_2 = 30 \text{ kW} \tag{i}$$

Given, power factor $\cos \phi = 0.4$

$$\therefore \quad \phi = \cos^{-1}(0.4) = 66.4°$$

From Section 5.3 (two-wattmeter method),
We know that

$$\phi = \tan^{-1}\left[\sqrt{3} \times \frac{W_1 - W_2}{W_1 + W_2}\right]$$

$$= \tan^{-1}\left[\sqrt{3} \times \frac{W_1 - W_2}{30}\right]$$

$$\therefore \quad \sqrt{3} \times \frac{W_1 - W_2}{30} = \tan \phi = \tan 66.4 = 2.29$$

$$W_1 - W_2 = 39.7 \text{ kW} \tag{ii}$$

Solving (i) and (ii), we get

$$W_1 = 34.85 \text{ kW and } W_2 = -4.85 \text{ kW.}$$

PROBLEM 5.4 A 230 V single phase watthour meter (energy meter) records a constant load of 10 A for 4 hours at unity power factor. If the energy meter disc makes 2760 revolutions during this period, what is the energy meter constant in terms of revolutions per unit? Calculate the load power factor if the number of revolutions made by the energy meter is 1104 when recording 5 A at 230 V for 6 hours.

Solution: Actual energy consumed by the load in 4 hours:

$$= VI \cos \phi \times t = 230 \times 10 \times 1 \times 4 = 9200$$

$$= 9.2 \text{ kWh.}$$

$$\therefore \quad \text{Energy meter constant} = \frac{\text{Number of revolutions made}}{\text{kWh consumed}}$$

$$= \frac{2760}{9.2} = 300 \text{ rev/kWh}$$

$$\therefore \text{ Energy corresponding to 1104 revolutions} = \frac{1104}{300}$$

$$= 3.68 \text{ kWh}$$

Thus $$VI \cos \phi \times t \times 10^{-3} = 3.68 \text{ kWh}$$

$$\therefore \quad \cos \phi = \text{ Power factor} = \frac{3.68}{230 \times 5 \times 6 \times 10^{-3}}$$

$$= 0.553$$

Hence, the power factor of the load = 0.553

EXERCISES

1. If the speed of a turbine is controlled by a linear steam governor and the turbine load L and steam flow Q are governed by the relationship $Q \alpha L^2$, calculate the percentage opening of the governor at 50% of the load.
2. Enumerate the essential steam turbine parameters that should be monitored and controlled.
3. Name four critical parameters which are to be measured and alarmed in a turbine.
4. What are the different cooling systems exist in turbo generator?
5. In a turbine speed control system, the control valve used has a characteristics of steam output Q = constant $\times P^2$ where P is the position of the control valve in percentage and turbine speed $N \alpha Q$. Assuming that the maximum speed 1500 rpm is achievable with 120 T/hr of steam flow at 100% valve opening, calculate the valve position in percentage for 1000 rpm.
6. How are the speed and vibration of a steam turbine monitored?
7. What are the basic differences between safety control system and process control system in a turbine?
8. Group the important parameters to be measured in turbo-alternator into the following:
   (a) Mechanical parameters
   (b) Electrical parameters
   (c) Process parameters

9. Explain the temperature measurements with suitable ranges, suitable sensors, protection devices etc., for the following:
   (a) Shell temperature measurements
   (b) Bearing temperature measurements
   (c) HP and LP heater inner wall temperature measurements
   (d) Lube oil temperature measurement
   (e) Steam inlet temperature measurement

10. Explain in detail the monitoring and control of turbine speed.

11. Why speed control is required in a turbine?

12. Discuss about the various governors used for controlling steam input to the turbine for speed control.

13. Differentiate impulse and reaction turbines.

14. Name the classifications of turbines based on process conditions.

15. Where is the extraction turbine useful?

16. Name the principal parts of steam turbine and show them on a neat line sketch.

17. What are the different valves used in turbine inlet system?

18. Name and explain the two main characteristics of turbine governors.

19. How electronic governors differ from mechanical counter parts?

20. How do we measure condenser vacuum?

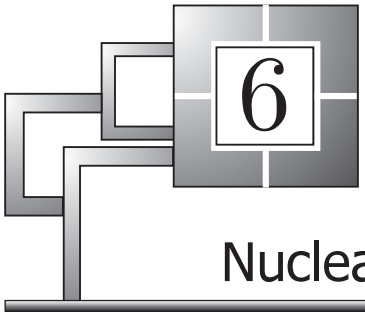
21. What are three basic controls expected in a turbine lubrication system?

22. Draw the control schematics for the control of pressure/flow, temperature and tank level in a lube oil system.

23. What are the different ways of measuring power factor in a three-phase system?

24. What are the advantages of using two wattmeter method over other methods for measuring three-phase power for unbalanced load?

25. Explain the different cooling methods for an electric generator. Why hydrogen cooling is preferred over others for large generators?



Nuclear Power Plant Instrumentation

6.1 INTRODUCTION

Both Nuclear Power Plant and conventional thermal power plant use steam to produce electricity through a turbo alternator. The sources of heat energy to produce steam in both power stations are different. The conventional one makes use of fossil fuels, like natural gas, furnace oil and coal. They are burnt in the boiler combustion chamber in combination with air, and the thermal energy thus released, is transferred to feed water to produce steam. The boiler may be either of water tube type or fire tube type. The energy released is controlled by controlling the air/fuel quantity and ratio. The major measurements and controls involved are discussed in Chapters 2 and 3.

In a Nuclear Power Plant (NPP), energy released by nuclear fission is used to produce steam. Nuclear reactions that occur at a steady rate should be controlled. Each fission releases energy which heats up the core of the nuclear reactor. This heat must be continuously removed through cooling fluid. The heat carried by the cooling liquid is used to generate steam either directly (boiler water reactor) or indirectly (pressurized heavy water reactor). To operate the reactor safely, the reactor should have well-engineered and reliable power regulating system, start-up system and shutdown system. The cooling system should include an emergency core cooling system also. The safety and protection systems should have adequate redundancy and diversity. The major safety concern while operating a nuclear reactor is the possibility of radioactive releases.

Thus, we may conclude that the control and instrumentation for conventional and nuclear power plants is identical as far as turbine and electrical generator are concerned. Some of the control loops in steam generator side may also be same. Mainly the measurements and controls in thermal energy side are different. Chapter 3 of this book is concentrated on air-fuel-flue gas circuit for combustion control or thermal energy control in a conventional plant. This chapter is deviated and concentrated on reactor control. In addition, radiation safety measurements and controls will be touched up on. The controls during starting up of a nuclear reactor and shutting down (either normal or emergency) will be also discussed.

6.2 INSTRUMENTATION AND CONTROL FOR NUCLEAR POWER PLANT

Instrumentation and Control (I&C) is an essential system for operation of Nuclear Power Plants during normal, abnormal and emergency conditions. Instrumentation and Control system includes different equipment, modules, sensors, and transmitters. They together measure number of variables, running into thousands, and processes the data to activate final control elements. The final control elements may be pumps, control valves, motors and other electro-mechanical equipment, like solenoid valves which are used to control the plant. The system senses basic parameters, like temperature, pressure, flow, level, neutron flux, etc., monitors performance of the reactor, steam generator and turbine, analyses the information and controls the plant operation automatically. The I&C system ensures the plant's safety in addition to efficient production of power by reacting appropriately to failures and abnormal events.

The roles played by I&C system can be broadly classified into three basic functions:

1. Acting as the plant's nervous system, it provides plant operators relevant information to take appropriate actions during normal and abnormal operation.
2. It facilitates the operator to put the plant and its associated systems in automatic control mode to maintain efficient and safe operation of the plant.
3. It does the critical function of protecting the men and machine whenever there are faults in the system, errors made by operators and extreme external events threatening the plant's operation. In case of accidents, the I&C system should enable the safe operation of the plant for an extended period without operator intervention.

In general, the I&C system of a Nuclear Power Plant must be accurate in sensing various parameters, quick in communicating the process variables and fast enough to provide protection against upsets in the plant and the ancillary systems. Overall, the I&C system should have greater redundancy and reliability.

6.3 IMPORTANT COMPONENTS OF I&C SYSTEM

The general classification of Nuclear Power Plant instrumentation can be brought under four categories of instruments:

1. Nuclear processes: Instruments that measure nuclear processes such as reactor power, neutron flux density, etc.

2. Non-nuclear processes: Instruments that are used to measure parameters, like reactor pressure, coolant level, steam and water flow, coolant temperature and flow, containment pressure, etc.

3. Radiation monitoring: Instruments used for detecting radiation in steam lines, gas effluents and leakage at the plant site.

4. Special instruments: Which are used for all other applications, like vibration, conductivity, hydrogen concentration and acid concentration, etc.

I&C components can be categorised function-wise as follows:

1. Sensors that measure process variables of common category such as temperature, pressure, flow, level, etc. Control, regulation and safety components connected with sensing also fall under this category.

2. The communication infrastructure that move sensor and control data through the system, wires, cables, fiber-optic and wireless networks, etc. are covered here.
3. Man-machine interfaces, such as displays, graphical and trend, historical, etc.
4. Diagnostic systems to monitor abnormalities in sensor signals.
5. Final control elements, such as control valves, pumps, motors and electro-mechanical devices to adjust processes for efficient and safe operation.
6. Alarms and annunciation systems to pre-warn the operators about abnormality in process.

Temperature, pressure, level, flow and neutron flux are the most important and safety-critical parameters to be measured for the control and safety protection of the nuclear reactors. In all these measurements sensors play a vital role. They usually have to reside in the harsh environment of the field. The basic mechanism of these sensors is still conventional ones. Temperature is measured using conventional sensors, like Resistance Temperature Detectors (RTDs), thermo-couples and pyrometers. The construction and protection devices for the sensors may change as per the location of the measurement. Similarly, pressure, level and flow are measured using conventional sensors, like bourdon tubes, bellows, diaphragms, capsules, capacitance cells, strain gauges, force balance sensors, motion balance sensors, pressure transmitters, differential head producers and Differential Pressure Transmitters (DPTs). Conventional neutron detectors are being used even today, though new neutron detectors are being developed. A typical Nuclear Power Plant of about 1000 MW capacity may contain about 1000 pressure and differential pressure transmitters for measuring process pressure, flow and level in its primary and secondary cooling systems. It is expected that the reader is already well conversant with basic temperature, pressure, level and flow measuring sensors, and hence, the measurement of neutron flux density sensors will only be discussed elaborately here.

Figure 6.1 illustrates a typical process measurement system in a Nuclear Power Plant.

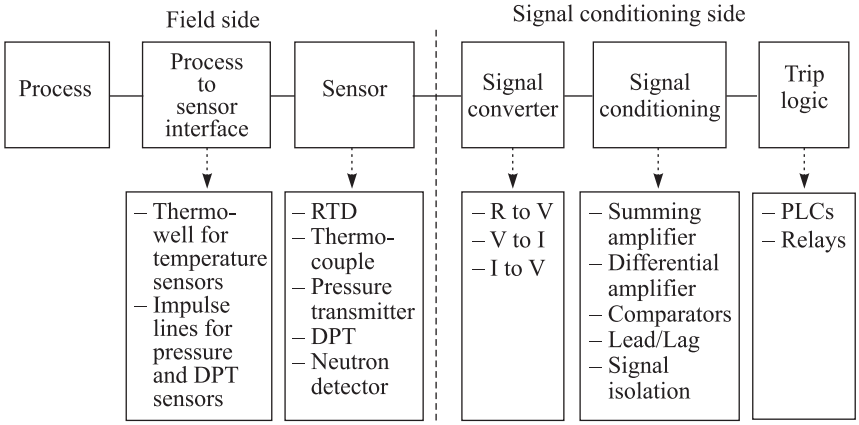


Figure 6.1 Typical process measurement systems.

6.4 EVOLUTION OF I&C IN NPP

The evolution of Instrumentation and Controls in nuclear power plants can be analysed in three generational shifts. Analog technology for instrumentation and mechanical relays for control of

discrete processes were used in first generation (before 1970s). The integrated solid state equipment was used in second generation for both Instrumentation and Control. The emergence of Programmable Logic Controllers (PLCs) replaced the mechanical relays. The third generation I&C is completely digital, and evolved from microprocessor-based PLCs and distributed digital control system. They can be programmed to perform complex tasks. Digital I&C replaced analog relays, suited for new applications in plant monitoring and control systems and provided graphical displays for man-machine interaction.

There are three important driving forces behind the evolution of I&C in NPP. The first has been the obsolescence of analog equipment. The second driver has been the development of new technology. Though sensor technology has not changed significantly, other I&C systems have undergone a major shift. The third and very important driving force is the accidents that happened in NPPs. Accidents of Three Mile Island in USA, Chernobyl in Russia and Fukushima in Japan, forced the designers to reevaluate principles of operation robustness of the system, safety margins, and accident probability assumptions.

6.5 SENSORS AND MEASUREMENT SYSTEM

The sensing element, transducer and signal conditioner used in NPP are based on conventional instruments and methods. The process variables measured for control and safety related applications are temperature, pressure, flow, level and neutron flux density. The sensing technology adopted for the above variables is a well-established measurement concept. Therefore, the discussion will be focused on some of the special temperature measuring techniques and concentrated mainly on neutron flux density measurement as they may not find a place in common books meant for sensors and measurement systems.

6.5.1 Thermometry

This section gives a brief account of special sensors recently developed for temperature measurements in NPP.

Distributed fiber-optic Bragg thermometer

This technique may be used to monitor the health of electro-mechanical components in nuclear power plant. The measurement is based upon a series of Bragg gratings arranged along the core of a single mode optical fiber. The temperature dependence of the Bragg wavelength originates from the thermal expansion of the fiber, which results in detectable variation in the optical index of the core. As the sensor is non-conductive, it may be used in high electromechanical field environment, such as pump motors and turbo alternator. The lifespan is expected to be more in radiation environments.

Ultrasonic wireline thermometers

Ultrasonic wire line pulse-echo is suitable for reactor-vessel temperature measurement. The change in velocity of sound with in a wire with temperature is the principle used. The velocity of sound in a wire changes with its elastic modulus and density which are temperature dependent. The sound velocity increases with increase in modulus, and decreases with increase in density. But the order

in which modulus increases with temperature is very high compared to that of decrease in density. The relation is given by the equation as follows:

$$v(T) = \sqrt{\frac{Y(T)}{\rho(T)}}$$

where

$v(T)$ = Sound velocity
$\rho(T)$ = Density
$Y(T)$ = Young's modulus

An extensional wave is launched down a waveguide. The return time of reflections are recorded. The wire line contains notches at definite lengths. The time difference between reflections from each of the notches is indicative of temperature.

Johnson noise thermometer

This is attempted to avoid drift in temperature measurements using known common thermometer elements due to harsh environment in NPP. Johnson noise is a fundamental representation of temperature, and is immune to chemical and mechanical changes in the material properties of the sensor. Johnson noise thermometer measurement is applied in parallel to conventional measuring circuit and the temperature is computed out of these two signals.

Gamma thermometers

Gamma thermometer is normally used to measure the heat generated out of gamma rays with the help of a thermocouple. Final measurement, a function of gamma flux, is in turn proportional to the local power generation rate.

Type-N thermocouples

Type-K thermocouples are normally used as standard thermocouples in Nuclear Power Plants. They exhibit a long-term cumulative drift in Seebeck coefficient when exposed to elevated temperature for long duration. Type-N (Nicrosil-Nisil) thermocouples are developed to overcome the above deficiency of Type-K thermocouples.

6.5.2 Neutron Flux Density Measurement [Ionization Sensors]

In a nuclear reactor, the thermal power level is proportional to the neuron flux density for a given fuel enrichment. The selection of the instrument should be such that it responds quickly of the neutron flux change so that the measurement can provide the instantaneous reactor power. Such information is of very great value for the safe operation of nuclear reactor. Neutron sensors can be located suitably either within the core or outside.

The neutrons have the ability to cause indirect ionization in suitable circumstances. This property of the neutrons is widely used to measure neutron flux density in the reactor core. Ionizing particles are emitted when neutrons take part in certain nuclear interactions. When fast neutrons of about 0.1 MeV energy or more pass through hydrogen gas, they can transfer the energy to hydrogen nuclei by elastic scattering. As a result the protons recoil, move with high speed, and produce considerable ionization. The reaction of slow neutrons with boron-10 produces helium and lithium nucleus. Both of them will have relatively high energy and are capable of causing

ionization. Slow neutrons may induce fission of uranium 235. The fission fragments, thus, resulted can produce large number of ion-pairs in their paths.

Behaviour of ion-pairs in an electric field

The ion-pairs formed by the ionizing particles in their passage through a gas exhibit a definite behaviour in an electric field. To explain the phenomena one may consider two electrodes arrangement placed in a vessel of gas. A metal cylinder and a metallic wire running along the axis of the cylinder act as negative electrode (cathode) and positive electrode (anode) respectively as shown in Figure 6.2. When the ionizing radiation enters the gas between the electrodes, a definite number of ion-pairs are formed. The positive ions then move towards the negatively charged electrode and the electrons move towards the positive electrode. The amount of charge collected on the electrodes will be based on the applied voltage.

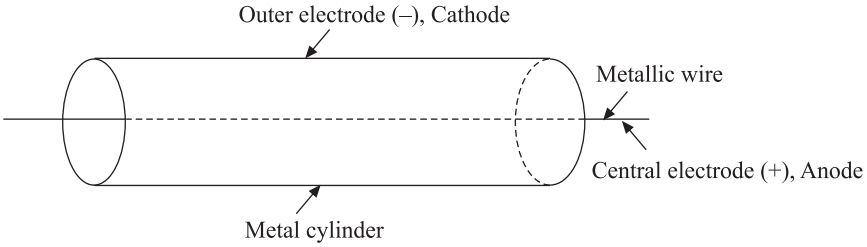


Figure 6.2 Electric field for study of behaviour of ion-pairs.

The general nature of the variation of magnitude of the charge collected and the applied voltage approximately linearised is shown in Figure 6.3.

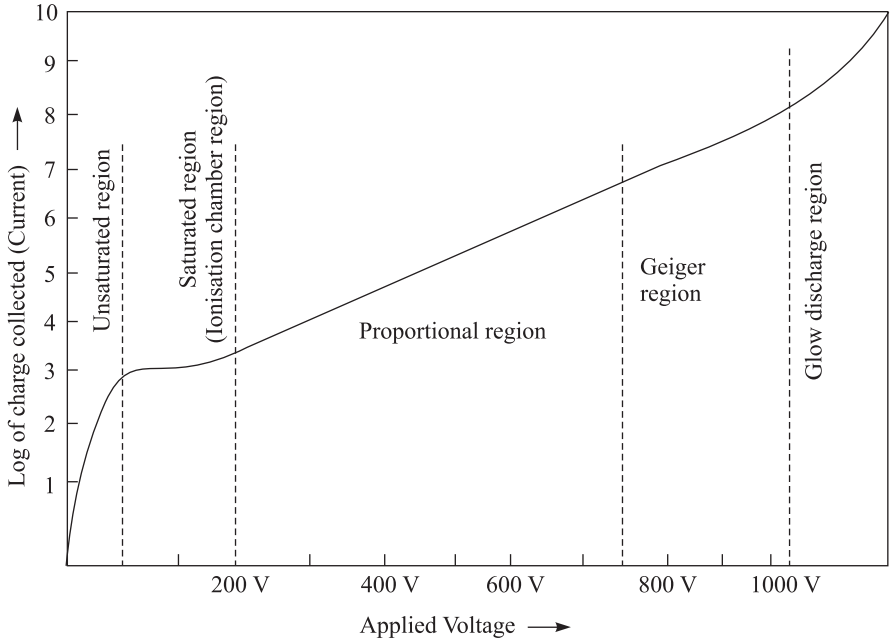


Figure 6.3 Variation of charge collected with applied voltage.

At low voltage some of the ions generated by the incident radiation will not become absorbed by the cathode, since they become neutral molecules again. This portion is called unsaturated region. As the voltage increases however, the charged ions migrate more rapidly towards the respective electrodes. The extent of recombination is thus reduced, and the charge collected on the electrodes increases. With more voltage, the rate of collection of charges reaches a saturation value and remains there. In this region, the ions and electrons move so fast that the recombination is virtually zero. That means every charged particle produced by the nuclear radiation reaches the electrode. Normally, the ionization chambers work with this saturation region. In this region the charge remains constant as the voltage is increased.

However, the ionization region (saturation region) has a limited range. A new phenomenon happens when the applied voltage is further increased. The quantity of charge collected for a given amount of radiation becomes more than, but proportional to the original amount of ionization. This region of operation is called as proportional region. Because of high potential gradient, the primary electrons move fast enough to cause secondary ionization in the gas. The secondary ionization may cause further ionization and so on to initiate a chain of (avalanche of) ionizations. The ratio between primary ion pairs and the total number of ion pairs produced is called the 'gas amplification factor'. This factor is unity in the previous ionization chamber region, and is higher in the proportional region.

Further increase in applied voltage forces the ionization avalanche, so far confined to small region of the positive electrode, to spread over the whole of its length. In this region, the total amount of charge collected is independent of the primary ionisation. This region is called 'Geiger region'.

With the increase of applied voltage beyond the Geiger region, rapid increase in the collection of charge results. There is effectively a continuous discharge once a discharge is initiated. This region is not utilized for measurement of ionization radiations.

Ionisation chambers

A number of instruments for measurement of neutron flux density operate in ionization chamber region. As seen already, the charge collected by the electrodes is equal to that carried by the primary ion-pairs. Most of such measurements may be categorized into two types, namely, integrating and non-integrating. The integrating type instruments collect the total quantity of charge carried by a number of ionizing particles over a period of time. The non-integrating type instruments record separately each particle of ionization.

Integrating type instruments can be further classified into two categories. They are electrostatic and electrodynamics types. The electrostatic type of instrument is also known as electroscope, and is not used for reactor control purpose, but used for surveying or monitoring for human safety point of view. Hence, the electrodynamics type of integrating type instrument will only be dealt with here.

Direct current ionisation chamber

The simplified diagram of an electrodynamics or current indicating type ionization chamber is shown in Figure 6.4. A DC potential is maintained between the electrodes by means of a battery. The ions and electrons produced due to entering of sufficiently high rate ionizing radiation are continuously collected by the electrodes. Then a steady current which is a measure of ionizing particles entering, flows through the circuit. This direct ion current may be measured directly or using a high-impedance voltmeter.

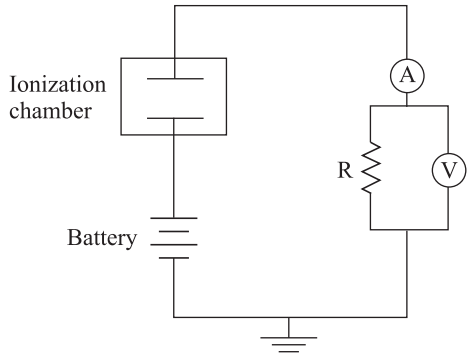


Figure 6.4 Integrating direct–current ionization chamber.

The ionization chamber meant for detecting fast neutrons is filled with hydrogen or with a hydrocarbon gas. The interior walls are lined with a hydrogenous substance, like paraffin or polyethylene. The liberation of recoil protons of high energy on exposure to fast neutrons produces ionization, and hence, the ionization current. The current thus produced is a measure of the neutron density (or flux).

The measurement of slow neutrons is done by coating the electrodes with boron, preferably enriched with boron-10 isotope. Boron-10 has a large absorption cross-section of slow neutrons. Coating with uranium 235 compound is also possible. The slow neutron causes fission, and the resulting fragments produce considerable ionization in the gas.

When sensor is located in the reactor core, it is exposed to high neutron fluxes. The sensitivity of the sensor is high, whereas it is exposed to high temperature. The sensor constructional material has to be selected to withstand the high temperature. When the sensor is located outside the core, the neutron fluxes are lower, and hence, a more sensitive sensor has to be used. To increase the sensitivity, parallel and cup-shaped electrodes are used. Number of boron coated flat, circular and parallel plate electrodes are connected alternatively to achieve the same objective. Such an instrument, called PCP (Parallel Circular-Plate) chamber, responds quickly to a change in the neutron flux in the reactor core.

Because of the gamma radiation from fission process, the neutron flux measuring instruments are to be compensated for gamma rays. A simplified gamma rays compensated ionization chamber is shown in Figure 6.5.

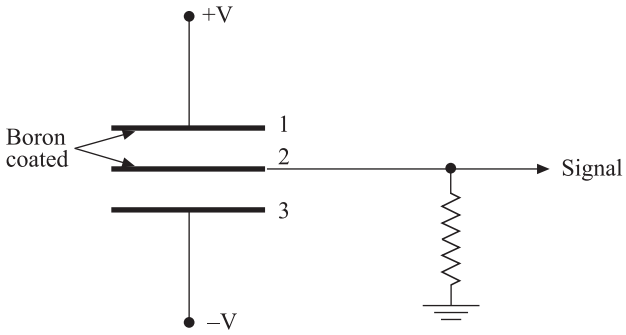


Figure 6.5 Compensated ionization chamber for neutron flux measurement.

The instrument consists of three cup-shaped parallel electrodes. Electrodes 1 and 3 are connected to voltage source of opposite polarity. Electrode 2 the collecting electrode, is grounded through a measuring circuit. The position of Electrode 2 is such that the amounts of ionization produced by gamma rays in Electrodes 1 and 3 are same, but in opposite polarities. Hence, the net ion current towards collecting Electrode 2 will be zero. Since the Electrodes 1 and 2 are boron coated, the resulting ion current will be the measure of the neutron flux.

Pulse-type ionizing chamber

The ionizing current will be series of pulses instead of continuous one whenever the time constant of the ionization chamber is smaller than that of the average time between the arrivals of successive ionizing particles. The entry of an ionizing particle is then represented by a pulse. Such an ionization chamber is known as pulse-type chamber which can be used to measure neutron densities even in the presence of considerable intensities of gamma and beta rays. The pulse produced by the entry of neutrons will be much greater than those pulses produced by gamma and beta particles. The output circuit is usually designed to eliminate weaker pulses and allow only larger pulses. The pulse chamber will be normally lined with boron or filled with boron trifluoride gas for detecting neutrons. Since the rate at which neutrons enter the chamber is a measure of the local neutron flux, a counter is employed for use in reactor control. When the interior of the chamber is coated with a uranium compound enriched with uranium 235, it is called as 'fission chamber'.

Proportional counters

The proportional counters operation is in the proportional region (Refer Figure 6.3). The internal gas amplification in this region helps to have less external circuit amplification. Also, as the internal gas amplification increases with voltage applied, the counting of highly ionizing particles (like neutrons) becomes easy compared to those of low ionizing particles out of gamma rays and beta rays.

The electrodes arrangement is similar to that of the one shown in Figure 6.2. The electrodes consist of a cylinder and a central wire. The central wire, the collecting electrode, is connected to the external amplifier for further processing the signal. As the name proportional counter implies, pulse counting technique is always employed here. The hydrogen gas may be filled in the chamber for fast neutron measurements. For slow neutron densities either the electrodes may be boron coated or the containing tube may be boron coated or the containing tube may be filled with born trifluoride gas. Such proportional counters are also called as boron counters. Boron counters are normally used during the startup operation of the reactor when the neutron flux is very low.

6.5.3 Non-ionization Neutron Flux Measurement

Instruments have been developed for measuring slow-neutron flux which does not depend on ionization. They are small in size and can fit into narrow spaces. They are rugged, and hence, withstand the reactor core environment. They can indicate the spatial flux distribution by having number of such sensors distributed throughout the reactor core. Average power level can be obtained with such measurements. The response is so slow that they can be employed only during reactor's stable power operation and not for reactor control.

Self-powered neutron detector

Self-powered neutron detector does not require external applied voltage as the name suggests. It measures the electron current resulting from the beta particles emitted by a material activated by neutron capture. In majority of the cases, the material to be activated is rhodium isotope. The sensor consists of a rhodium wire (emitter) surrounded by magnesium oxide (insulator) and enclosed by an inconel sheath as shown in Figure 6.6.

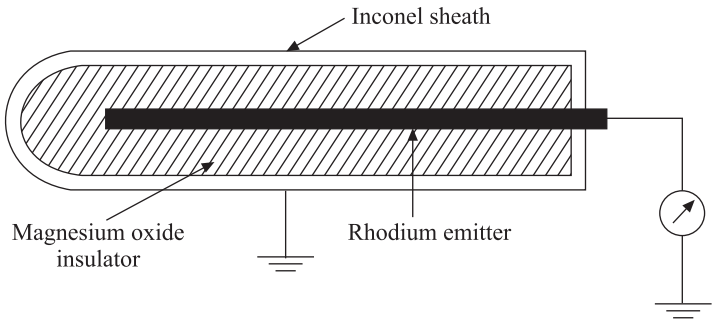


Figure 6.6 Self-powered neutron detector.

The sensor's response time cannot match with a rapid increase in the neutron flux, and hence, not suitable during reactor start-up. At full power operation it may indicate a value proportional to the neutron flux.

Neutron thermopile

Neutron thermopile is another type of non-ionizing neutron sensor. The sensor is made up of number of thermocouples with alternate junction coated with boron-10. The heat generated due to absorption of neutrons by boron develops millivolts in the thermocouples, which is the measure of neutron flux. Its long response time makes it unsuitable for measuring local neutron fluxes. The thermal power level may be determined by averaging the millivolts developed by thermopiles distributed throughout the core.

6.5.4 Location of Neutron Sensors

It is very important to decide before hand, the location of the neutron sensors. It is possible to choose the location within the reactor core or outside the core. The sensors located outside the core normally measure the average flux. The in-core devices may give the spatial power distribution within the core.

Out-of-core sensors

Out-of-core sensors are located outside the reactor vessel where temperature is moderate. Ionization chambers and proportional counters are commonly employed. No special material is required for their construction. The sensors must be sensitive to lower fluxes, as the flux density outside the core will be less. The sensors are used to measure the average flux.

In-core sensors

In-core sensors may be of either fixed location type or of movable type. Fixed sensors located at various points give three-dimensional flux distributions. Movable neutron sensors, on the other hand, provide axial distribution of flux. As in-core sensors are exposed to intense neutrons and gamma radiation, and hence, the possibility of construction materials getting damaged. They are also exposed to high temperature and high pressure. The sensors must be small in size, enclosed in a water tight and corrosion-resistant compartment, and be able to withstand high temperature and high pressure. In spite of all the above precautions, the life span of sensors is short as compared to out-of-core sensors. The movable in-core sensors may be kept in locations where neutron flux is relatively low when not in use.

Fission chambers are the most common in-core neutron flux sensors. They are pulse-type ion chambers coated with a uranium compound enriched with uranium 235. The common materials used for outer cylindrical electrode are titanium and stainless steel. The collector electrode is normally made of titanium. In some cases, the collector and the housing are made of stainless steel, and the outer electrode is of enriched uranium—aluminum alloy. The chamber gas is argon and the insulating material is alumina in most of the sensors. Fixed and movable in-core sensors are used for start-up and power operations. Self-powered neutron detectors and boron thermopiles are often used as fixed in-core sensors.

6.5.5 Ranges of the Neutron Flux Sensors

Neutron flux variation from start up of the reactor to normal operating level may be by a factor of 10^{11} neutrons/m^2.s or more. It is always better to know the flux density over the whole range. During start-up, the neutron flux level has to be kept minimum, and then raised to reach the operational level slowly.

No single sensor can provide satisfactory measurement of neutron flux density over the whole range. In general, the whole range is divided into three ranges with some overlapping. They are:

1. Source range (from 10^{-11} to 10^{-6} neutrons/m^2.s)
2. Intermediate range (from 10^{-8} to 10^{-1} neutrons/m^2.s)
3. Power range (from 10^{-2} to 10^{18} neutrons/m^2.s)

During start-up of reactor, the neutron flux is low. When the reactor is started after shut down, the neutron flux will be low, but the gamma radiation will be high. Under these conditions one can use a pulse type fission ionization chamber or a boron proportional counter.

In the intermediate range, direct current ionization chamber may be used as the neutron flux is large enough for indication. Compensated ionization chamber is commonly used for outside the core measurement in Pressurized Water Reactor (PWR). In-core fission chambers are preferred for Boiler Water Reactor (BWR).

Accuracy and sensitivity are the essential requirements for measuring neutron flux density in the power range. Compensated ionization chambers and direct current integrating fission chambers are used for this range. As the neutron flux range is not large, the current output can be amplified linearly rather than logarithmically. Parallel Circular-Plate (PCP) ionization chambers are used wherever quick response is demanded for safety reasons.

6.6 REACTOR CONTROL

The electrical power generating capacity of a nuclear power plant is dependent on the mass of fissile material present in the reactor core, the fission cross-section, and neutron density. For instantaneous power variation, the neutron flux density will be useful information for controlling reactor. The heat generating capacity of the reactor, which can be directly linked to the power generating capacity of the plant, can be controlled by controlling the neutron flux.

The total reactor control system can be divided into three parts:

1. Provision for starting the reactor and bringing the power output to the desired level. Both fresh starting of the reactor and starting after shutdown or tripping are included here.
2. Maintenance of required power level during normal operation of the reactor.
3. Provision for shutting the reactor down both during normal course of operation and during emergency due to potential unsafe conditions.

One should clearly understand an important feature of a nuclear reactor. In most of the power reactors, the continuous replacement of fuel is not possible. It may be noted that CANDU reactors, which use natural uranium as fuel and heavy water as moderator, are designed for fuel replacement during normal operation. In fast breeder reactors fuel replacement poses fewer problems because, fissile material is produced by breeding during reactor operation. But in other common reactors enough fuel is filled in the beginning of each operational period to produce a pre-determined quantity of energy. Additional fuel is also required to compensate for fission-product poisons and the negative temperature coefficient. To account for the above reasons excess fuel is always filled while assembling the thermal reactor core before commissioning operation. The excess fuel filled initially cause excess reactivity. The control system employed should be capable of creating negative reactivity to compensate for the built-in excess or positive reactivity. The compensation is naturally to be more in the beginning of the operation period and minimum at the end.

Apart from fuel mass, the macroscopic fission cross-section and the neutron flux decide the operating power level of a reactor. The cross-section essentially remains constant over a considerable time interval. Hence, the power level at any instant may be considered proportional to the neutron flux. Further discussions on reactor control will be based on this assumption only.

6.6.1 Methods of Control

The basic purpose of a reactor control system is to provide a steady electric power generation in all situations. Though there are different ways possible for control, the most practical and convenient way of doing is by controlling neutron flux. Different ways are possible to vary neutron flux while the reactor is in operation. As such four methods are in use as listed as follows:

1. Temporary addition or removal of fuel mass. As discussed already, adding and removing fuel in most of the reactors is not practical
2. Addition or removal of moderator material
3. Addition or removal of reflector material
4. Use of a neutron absorber

Though theoretically all the above four methods individually or in combination can be adopted, the use of a neutron absorber is commonly employed in power reactors.

Control rods

Boron and cadmium are found to be good neutrons absorbing materials. Insertion or withdrawal of such a material with large cross-section will help for absorbing neutrons, and hence, the reactor energy control. Cylindrical rods made out of boron or cadmium are fully inserted in the core when a reactor core is being assembled. The rods, which are the control elements, are generally known as 'control rods'. Other than boron and cadmium, the materials which are used as neutron absorbers are—boron-10, silver, indium, gadolinium and hafnium.

When the control rods are in fully inserted condition, they absorb most of the neutrons generated. The neutron density or neutron flux in that fully inserted condition is maintained at such a low level that the system has a large negative reactivity. The neutron multiplication factor is then significantly less than unity and the system is said to be in 'sub-critical' condition. During starting up of the reactor, the control rods are gradually withdrawn to a level where the neutrons generated is equal to the neutrons absorbed. At this point, the reactor is considered to be in 'critical' stage. Further withdrawal of the rods makes the system to reach 'super critical' stage. The neutron flux, is thus, allowed during the start-up period to increase at a safe and controlled rate to reach a magnitude to match with the desired operating power level of the reactor. The automatic control will further adjust the position of the rods so that the neutron flux and power level remain steady. During shutting down of the reactor, the control rods will be re-inserted into the core. The reactivity decreases, and hence, the reduction of the neutron flux as well as power output.

6.6.2 Control Loops

Both manual and automatic operations are required in a reactor for starting up, bringing the reactor to a normal operating level and maintaining it reasonably steady at that level. A simplied block diagram of such a control system is shown in Figure 6.7.

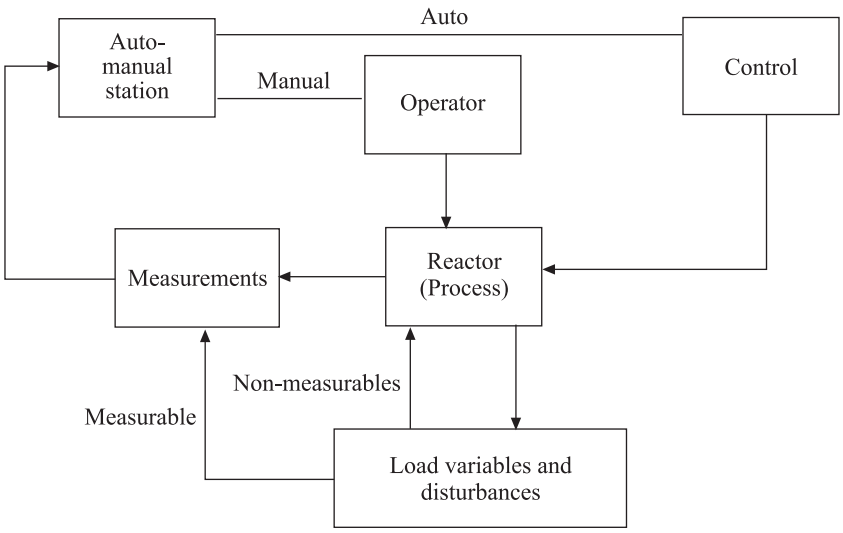


Figure 6.7 Basic block diagram of a reactor control system.

The policy adopted here is similar to any other general process industries. All important parameters are measured including neutron flux. During start up, the controls are put in manual mode and the operator operates the reactor with some safety controls in automatic mode. The operator moves the control rods up and down and exerts appropriate action knowing the reactor conditions including information about neutron flux. At steady state, control station takes over bypassing manual mode and performs automatic operation. In addition to power transfer control through control rods, all other parameters, like temperatures and pressures are also controlled automatically through the system. Other interactive parameters, like reactivity, coolant water flow, temperature, pressure, steam demand in the turbine, etc. definitely influence the performance of the control system. Some measurable and some non-measurable parameters are to be suitably dealt for reliable performance.

6.6.3 Functions of Control System

Regulation and shutdown functions are the two components of reactor control system. The regulation function involves the controlling of reactor power to match the power requirement on regular basis. This is a continuous function to take care of the transient changes in reactivity, variations in reactor water temperature, system pressure changes and change in steam demand. This is normally known as short-term adjustment activity. Fuel depletion and accumulation of fission-product poisons result in long-term changes in reactivity. The regulation rods have to take care of such an occurrence also. The control of long-term changes is called 'shim control'. As a shutdown control, the control system should decrease the reactor power level gradually during normal operation and very rapidly on emergency situation. A secondary function of the control rods is to 'shape' the neutron flux uniformly across the core. Insertion of control rods at appropriate locations will minimize the flux distortions.

The features of a reactor control system may vary with the type of reactors. The discussions will be limited to three general types of reactors, namely Pressurized Water Reactor (PWR), Boiler Water Reactor (BWR) and Liquid Metal Cooled Reactor (LMCR).

6.6.4 Pressurized Water Reactor (PWR) Controls

Control rods are combined in clusters [about 50 clusters with about 20 rods in a cluster] which are inserted or withdrawn from the top of the reactor. The rods are normally made of silver-indium-cadmium alloy. The clusters may contain full length rods or part length rods. In full length rods, the neutron absorber can extend to the full length of the core. In part length rods, only the lower quarter of the length will have absorbing material. There are normally two groups of full length rods. One group for regulation purpose and the other group for shut down purpose.

When the reactor is under shut down, all full length rods are inserted to the bottom, and part-length rods remain in the top. At the start-up, shut down rods are withdrawn first, and will remain in the top during normal operation. The regulation rods are withdrawn, one cluster at a time, in a sequenced manner till the power distribution is uniform and matches with the electrical load. Part-length rods are inserted to make the axial distribution of flux uniform. Up to 15% of loading, the reactors are controlled manually for safety reasons, and then put on automatic control.

Primary coolant flow controller

Fundamentally, the primary coolant water temperatures at the inlet and exit sides of the reactor vary with the change in electrical load. These temperatures are measured using platinum Resistance Temperature Detectors (RTDs) and signal conditioned with the help of Temperature Transducers (TTs). Also, the rate of flow of coolant water will have to vary for a designed temperature difference ($\Delta T = T_o - T_{in}$) with respect to electrical load. Hence, for coolant water flow rate control either one of the following three signals may be used as they represent the electrical load one way or other.

1. Electrical demand (output power)
2. Steam flow rate: Turbine inlet steam flow rate varies with electrical load
3. Steam pressure: Decreases with increase in electrical load, and hence steam flow and vice versa.

Hence, as a part of reactor control system, one has to first control the coolant rate to the reactor with reference to electrical load. The coolant rate may be steady most of the time when the plant is working at normal load. Even then, it is required to take care of the minor load fluctuations by having an automatic control system. Figure 6.8 shows a feedback control loop to take care of this aspect. Cooling water flow demand is fed as set point to the controller by selecting either one of the three signals as discussed. Coolant water flow rate is measured normally by having a head producer (say orifice) in the pipe line and a Flow Transducer (FT) as shown. The control loop parameters are to be tuned so that the coolant flow rate represents the electrical demand genuinely. In addition the coolant flow rate signal is parallely given to thermal energy controller of the reactor which is also called sometimes by the name ΔT (temperature difference) controller.

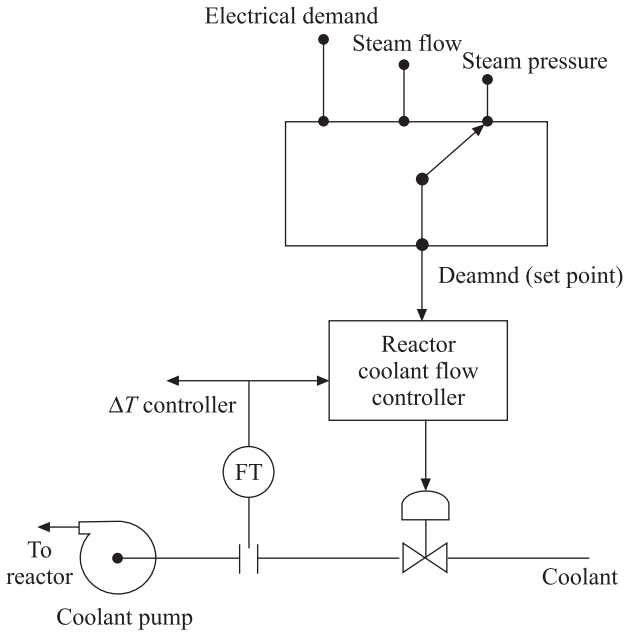


Figure 6.8 Coolant flow controller—PWR.

Feedback control of reactor thermal energy

Depending on the load requirement, the coolant flow has to change to meet the situation. For example, if the secondary steam has to increase for matching the increase in electrical load more heat transfer has to take place from primary coolant to steam generator. Hence, coolant flow has to increase so that the required heat transfer may effect. Also, the temperature difference between the coolant input to steam generator and output from steam generator plays a vital role.

The extraction of more heat from the primary coolant would decrease the temperature of the coolant water returning to the reactor. Hence, the difference between the programmed average temperatures for the electrical load concerned will give command signal to the actuator of the control rods. Then the insertion or withdrawal of control rods will take place to keep the temperature difference within prescribed limits. One such control loop in feedback mode is shown in Figure 6.9.

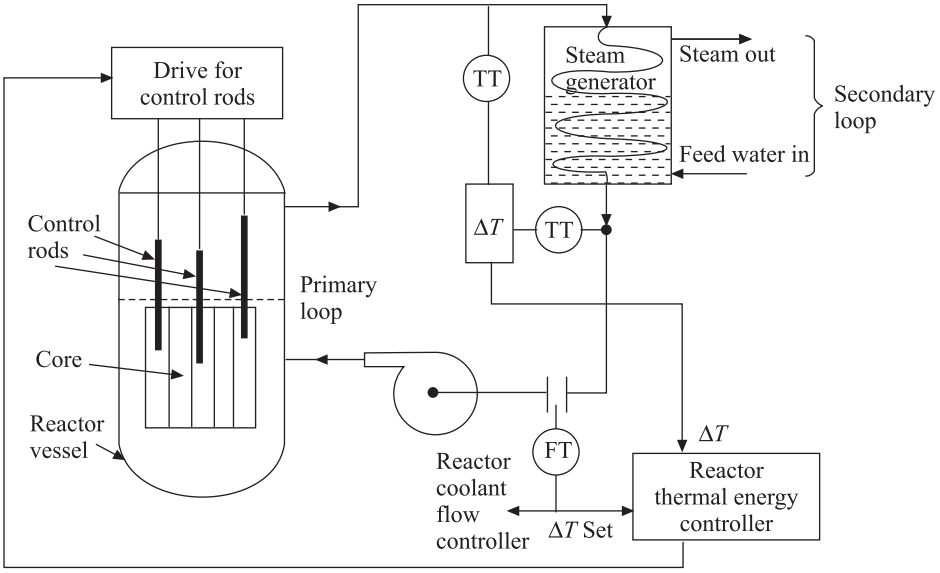


Figure 6.9 Feedback control loop—Reactor thermal energy control—PWR.

The control rods drive mechanism is always located in the top of the pressurized water reactor. The mechanism is little complicated, and has to operate different clusters of control rods differently, as already discussed. The operation of full length rods, short length rods, full length regulating rods and full length shut down rods are to be organized properly. For understanding purpose it is shown in a simplified fashion in Figure 6.9.

The working of the system can be explained as follows: Temperatures of the coolant inlet to the steam generator and the coolant outlet are measured and difference calculated. Such a signal of temperature difference (ΔT) becomes process value or actual value for the controller. The set value is the coolant flow itself as there is a relation exists between coolant flow and ΔT to be maintained at that coolant flow. The coolant flow rate itself is decided based on the steam demand as already discussed. The controller output actuates the control rods through drive mechanism to satisfy the ΔT requirement. This loop also works on feedback control mode only.

The temperature of the primary coolant coming out of the reactor and entering the steam generator is decided by the neutron flux density in the reactor. Hence, to have better stable control one can think of introducing neutron flux density measurement signal into the control loop. Such a system in a cascade mode is explained in the paragraph (Refer Figure 6.10).

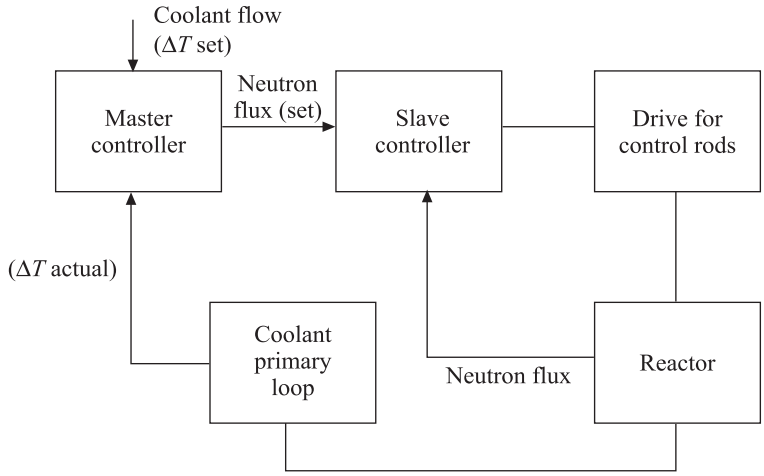


Figure 6.10 Cascade control loop—Reactor thermal energy control.

Cascade control for reactor thermal energy

The master controller of the cascade loop will receive coolant flow rate as set point. The temperature difference between the coolant inlet to steam generator and outlet from steam generator (ΔT) is given as process variable or actual value to the master controller. Coolant flow rate converted into an equivalent ΔT signal will be compared with actual ΔT measured. The error after amplification will be fed as set point to the slave controller (neutron flux controller). The slave controller takes neutron flux measured signal as the process variable or actual value, and compares with the neutron flux required signal (set point). The output of the slave controller actuates the control rods, and hence, controls the neutron flux generated to match with the set point.

Thus, the electrical load demand is matched with the neutron flux so that the nuclear power plant operates in the normal load automatically. The combined controls of feedback mode of coolant flow control (Refer Figure 6.8) and cascade mode of reactor thermal energy control provides stable operation of the plant with moderate electrical load fluctuations.

6.6.5 Boiler Water Reactor (BWR) Controls

Before going into the details of Boiler Water Reactor Controls, one should understand the basic principle of operation of BWR, and how it differs from that of Pressurized Water Reactor (PWR). In PWR, the secondary heat exchanger (steam generator) is located outside the reactor. The primary loop coolant which receives heat energy from reactor while flowing through reactor, exchanges that energy to the secondary loop liquid, feed water of the steam generator, to generate steam. Whereas, in BWR the primary loop coolant and the secondary loop liquid are one and the same.

The reactor vessel itself acts as steam generator or boiler, and hence, the name boiler water reactor. The coolant water boils in the upper part of the core and generates steam utilizing the heat liberated out of fission process. The feed water is recirculated by means of two recirculation pumps so that the heat exchange is uniform and efficient. The steam, thus generated, passes through steam separators and then through steam dryers before coming out of the reactor. Water particles from the steam, are thus, separated and the liquid returns to the vessel. The steam coming out of the reactor after this goes to the turbine. The temperature and pressure of the steam coming out of BWR is similar to that of the steam coming out of the steam generator in case of PWR. In both the cases, the steam is expanded in the turbine to run it and the exhaust steam is condensed, as usual, in any thermal power plant. The resultant condensate enters just above the core as feed water.

The control elements have a cruciform cross section. Each element has four blades at right angles. Blades contain vertical stainless steel tubes packed with boron carbide powder and move in spaces between the fuel rod assemblies. One control element for four fuel rod assemblies will be there. Unlike in a PWR, the control elements are inserted from the bottom of the reactor in BWR. This procedure helps a more uniform heat generation in the axial direction. The bottom entry of control rods facilitates the use of upper part of the reactor vessel for the steam separators and steam dryers. Thermal energy distribution is controlled by selected movements of control elements.

Coolant (feed water) flow and steam temperature controls

A feedback control loop can be employed to take care of turbine load demands. Increase in electrical load will demand more steam supply to the turbine. The supply of more steam from BWR is possible by increasing the circulation water flow into the reactor and simultaneously increasing the thermal energy transfer from core to the coolant by adjusting control rods. The process is reversed when the steam demand decreases. The whole control system is shown in a simplified diagram (Refer Figure 6.11).

Whenever the electrical demand increases the turbine will demand more steam (at constant steam pressure and steam temperature) from the reactor vessel to maintain the increased electrical load. The increased steam supply from the reactor has to be compensated by providing increased coolant (feed water) to the reactor. Hence, the coolant flow controller acts immediately on the increased steam flow (given as set point to the controller), and increases the coolant flow through the control valve till the coolant flow rate matches with steam flow rate. If the steam flow rate from the reactor vessel is increased without increasing the thermal input to the coolant the temperature of the steam will fall down which is not desired for turbine operation. Hence, the reactor reactivity has to be increased to supply more thermal energy to the coolant so that the final temperature of the steam can be compensated and brought to desired temperature. This action is taken care of by the second control loop. Steam temperature controller receives signal from steam temperature transmitter, compares with set point and produces control signal to alter the position of the control rods through control rods drive mechanism. As already discussed, the drive is fixed in the bottom side of the reactor and the rods are inserted/withdrawn from the bottom of the reactor. Withdrawal of control rods from the existing position will increase the reactivity, and hence, enhancement of thermal energy. The control rods finally settle down at a new position once the desired temperature is achieved at the increased steam flow rate. When the electrical load decreases the whole process reverses. The heat transfer from the reactor to the coolant depends

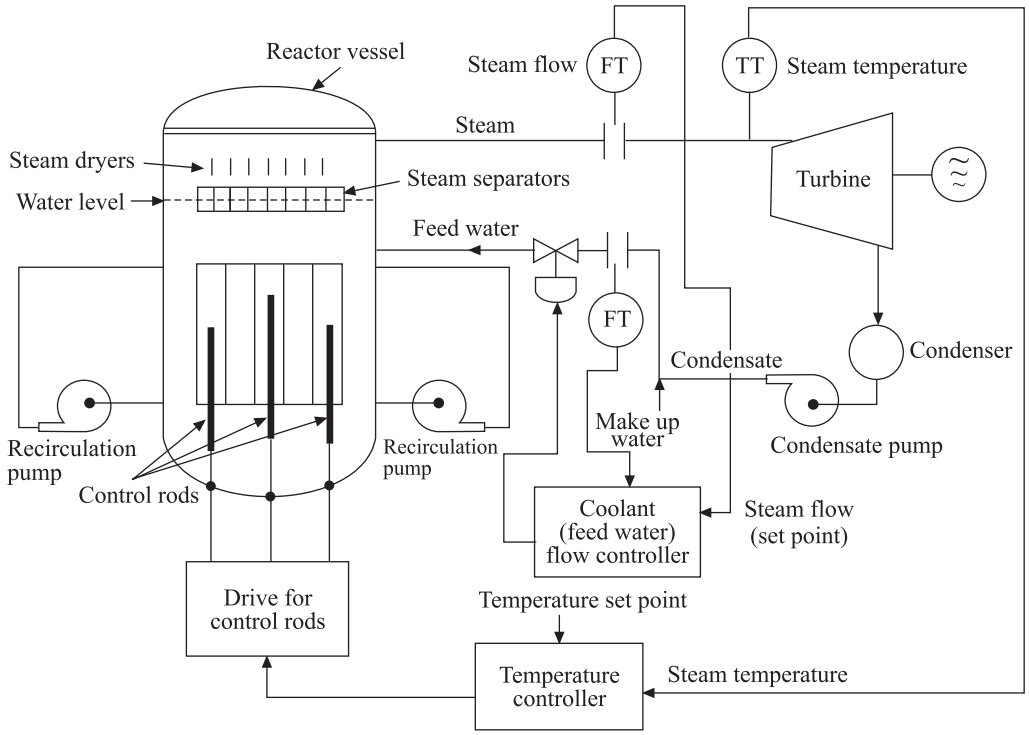


Figure 6.11 Coolant flow and steam temperature control—BWR.

entirely on the neutron flux density. Hence, the measured signal of neutron flux may be well-utilized in the control system to have a stable control. By adopting cascade control mode for the temperature control, the neutron flux density factor can be brought in.

Cascade steam temperature control

The master controller set point is the desired temperature of the steam for turbine operation. The process variable is the temperature signal measured in the steam pipeline, leading to turbine from the reactor. The master controller's output becomes the set point for the slave controller which receives neutron flux density as its process variable signal. The slave controller's output finally inserts/withdraws control rods so that the neutron density changes, i.e., the thermal energy transfer changes and hence, the temperature of the steam is brought to set point. The control process is schematically shown in Figure 6.12.

6.6.6 Liquid Metal Cooled Reactor (LMCR) Controls

In a Liquid Metal Cooled Reactor (LMCR) graphite is used as moderator and sodium (Na) as primary coolant. An alloy of sodium and potassium (Na-K) is used as intermediate heat exchanging fluid. Slightly enriched uranium is used as fuel. A high temperature operation is possible with liquid metals to achieve higher efficiency. Obviously, heat exchanging operation is taking place twice outside the reactor, and once inside the reactor. We may recall that heat exchanging takes

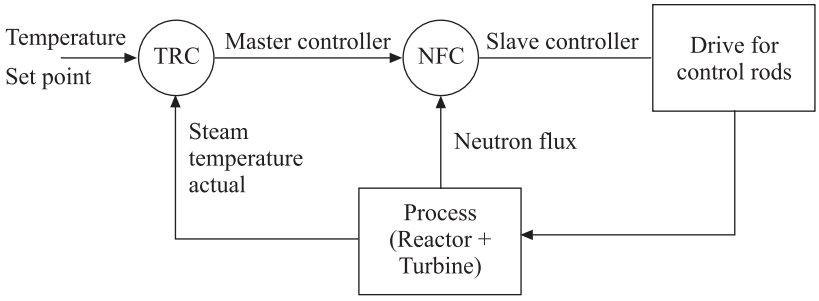


Figure 6.12 Cascade steam temperature control—BWR.

place once in BWR and twice in PWR, but thrice in LMCR. The heat generated by the reactor is carried away by the primary coolant (Na) and exchanged with the secondary loop liquid (Na-K) in the intermediate heat exchanger. The heat carried by Na-K is exchanged with boiler water to generate steam in Steam Generator (SG) or boiler. The Liquid Metal Cooled Fast Breeder Reactor (LMCFBR) controls will be similar to LMCR controls.

Control schematic for a LMCR

Figure 6.13 gives rough idea of LMCR controls. Taking the command from power setting device and power demand logic, steam flow, and hence, the feed water flow required is controlled through a water flow controller. Heat energy transfer from reactor to primary liquid loop is also parallely controlled. This is achieved with the help of reactor regulating and control system taking feedback from neutron flux density measurement. As the final steam temperature is important for turbine operation, steam temperature measurement is used as main signal for controlling the speeds of the primary pump and secondary pump. Power vs (Na) primary coolant flow chart, and pump speed setting device initiate the control action and pump speed controllers complete the process. The coolant circulation rates in primary and secondary loops, which are controlled by pump speeds, finally decide the heat transfer rates in intermediate heat exchanger and steam generator to maintain the final steam temperature (T_s) at the desired level. Steam temperature signal is also provided to water flow controller as corrective signal to have correlation between rate of increase/decrease in water flow and steam temperature. The steam pressure is controlled independently.

6.6.7 Role of Reactor Controls during Start-up, Normal Operation and Shut Down

As already discussed, the main functions of reactor control are:

1. For starting the reactor safely and smoothly,
2. For bringing up the power output to the desired level and maintaining it, and
3. For shutting it down in the course of routine operation as well as during emergency.

Reactor start-up control

The reactor start-up can be classified into three categories, namely, initial start-up, start-up after trip and power range start-up.

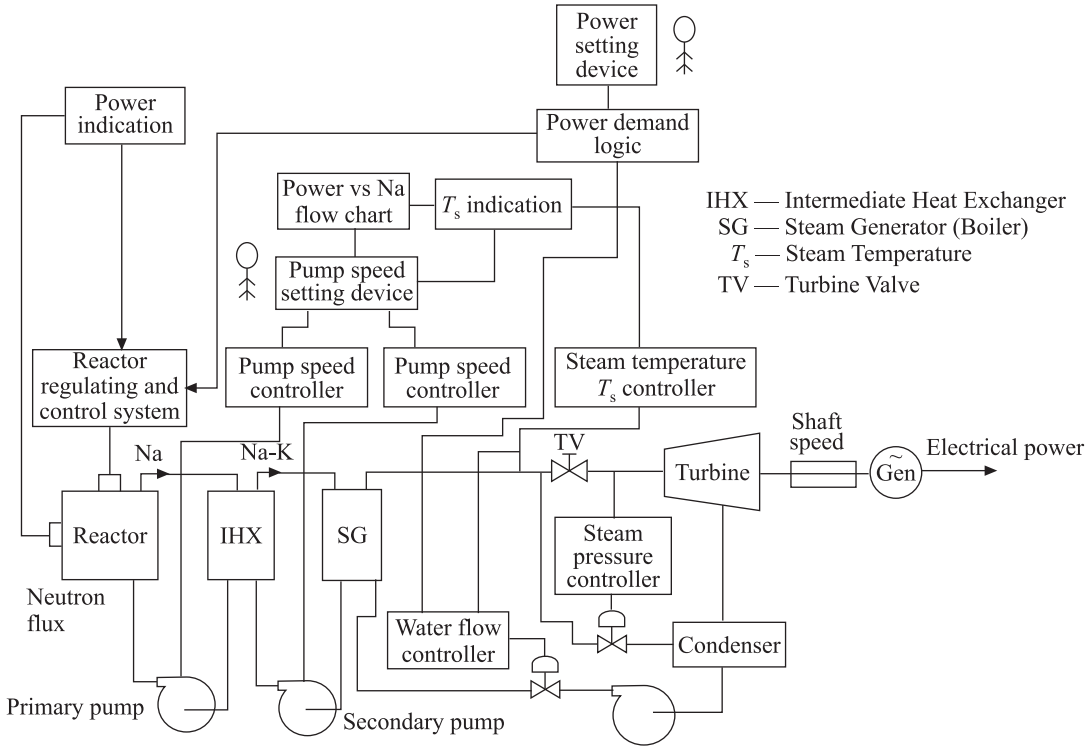


Figure 6.13 Control schematic for a Liquid Metal Cooled Reactor (LMCR).

1. Initial start-up: Initial start-up, also called as start-up from cold, applies to the starting of a new reactor. Careful attention is required while starting in order to avoid the possibility of an accident. Normally, a reactor is designed for high neutron flux with excess fuel-filled to take care of the definite period of running the reactor. This is necessary to compensate for the spent fuel during operation, because refuelling during operation is not desired. Having considerable excess built in reactivity, the possibility of attaining criticality, and crossing that stage in short duration is there. If it is allowed to continue without restrictions, the power may exceed rapidly the normal operating power causing serious consequences.

The start-up operation consists of bringing slowly and carefully to critical, and then increasing the neutron flux in a controlled manner to reach the desired level. Neutron flux measurements may not be possible when the level is very low. Till the level is brought to a value measurable by the sensor, the control rods should not be moved. Such a detectable neutron flux may arise from spontaneous fission of the fuel. To avoid reactor going to critical in a very short time, careful regulation of the rate of controlled withdrawal of control rods is essential during start-up. Initially, the control rods nearest to the core boundary may be withdrawn as they have the least worth. Control rods may be withdrawn slowly and intermittently instead of continuously.

2. Start-up after trip: Start-up after trip or a brief shutdown is less dangerous than initial start-up. In this case the neutron flux will be in a measurable range, and one can depend very well

on the measurement. If the shutdown is prolonged for a long time, the neutron flux will be decreased to a level where the neutron flux meter may not be able to read correctly. In such a case, the reactor has to be started as in initial start-up.

3. Power range start-up: In certain cases, the power level of a reactor is reduced to a minimum, say; one per cent of its full operating level. The neutron flux availability at this level may be so high that neutron flux instrument may read reliably. Then the start-up operation is simple and straight forward. The control rods can be withdrawn in a prescribed manner and at a slow rate to avoid potentially dangerous situations.

Normal operation

The required power level is maintained by automatic control as described earlier during normal operation. The error caused while operating is corrected back by the controller with the help of servomechanisms. The neutron flux, the coolant temperature, steam generated or power demands are some of the measured operating parameters used for control purposes. Recirculation rate, control-rod motion, etc., are the manipulating variables depending on whether feedback control or cascade control mode is engaged.

Reactor shut down

Under normal shut down conditions, relatively slow insertion of control rods is exercised. Rapid shut down is avoided, though possible, to decrease the thermal stresses in components of the reactor system. If the shut down is temporary to carry out repair and maintenance externally, the neutron level will be maintained at a safer level so that restarting can be simplified.

During potentially dangerous situations, the reactor must be shut down rapidly rather tripped automatically. Normally, the trip operation is part of the reactor protection system, not of the control system.

6.7 DIGITAL ARCHITECTURES IN NUCLEAR POWER PLANTS

The computer-based control and data logging system along with distributed control system for conventional fossil fuel based thermal power plants is already covered in Chapter 4. Similar digital architectures are already in operation in the modern Nuclear Power Plants. In this section, a typical digital architecture for a Nuclear Power Plant will be discussed. A fully-digital and network communication architecture with analog trip back-up is normally deployed. The focus of the digital communication design will be on the following three issues:

1. Electrical and functional independence between safety and non-safety areas
2. Assurance of fail-safe communication among safety systems
3. Common Cause Failures (CCFs) should not compromise the function of the safety systems.

6.7.1 System-level Instrumentation and Control Architecture

The Nuclear Power Plant Instrumentation and Control architecture is planned in three levels:

1. Level 0 systems: It is process interface level. This level acts as physical interface between Level 1 systems and sensors, actuators, and switch gear.

2. Level 1 systems: It is system automation level. Level 1 systems accommodate Protection System (PS), Safety Automation System (SAS), Process Automation System (PAS), and Reactor Control, Surveillance, and Limitation (RCSL) System.

3. Level 2 systems: It is called as unit supervision and control level. It consists of workstations and panels of Main Control Room (MCR), Remote Shut down Station (RSS), Technical Support Centre (TSC), Process Information and Control System (PICS) and Safety Information and Control System (SICS).

Both safety-related and non-safety-related systems are distributed in each level. A block diagram illustrating the main instrumentation and control systems and sub systems is shown in Figure 6.14. In the shown configuration, safe shut down states are either automatically generated in the SAS or manually initiated and processed by the PICS and SAS.

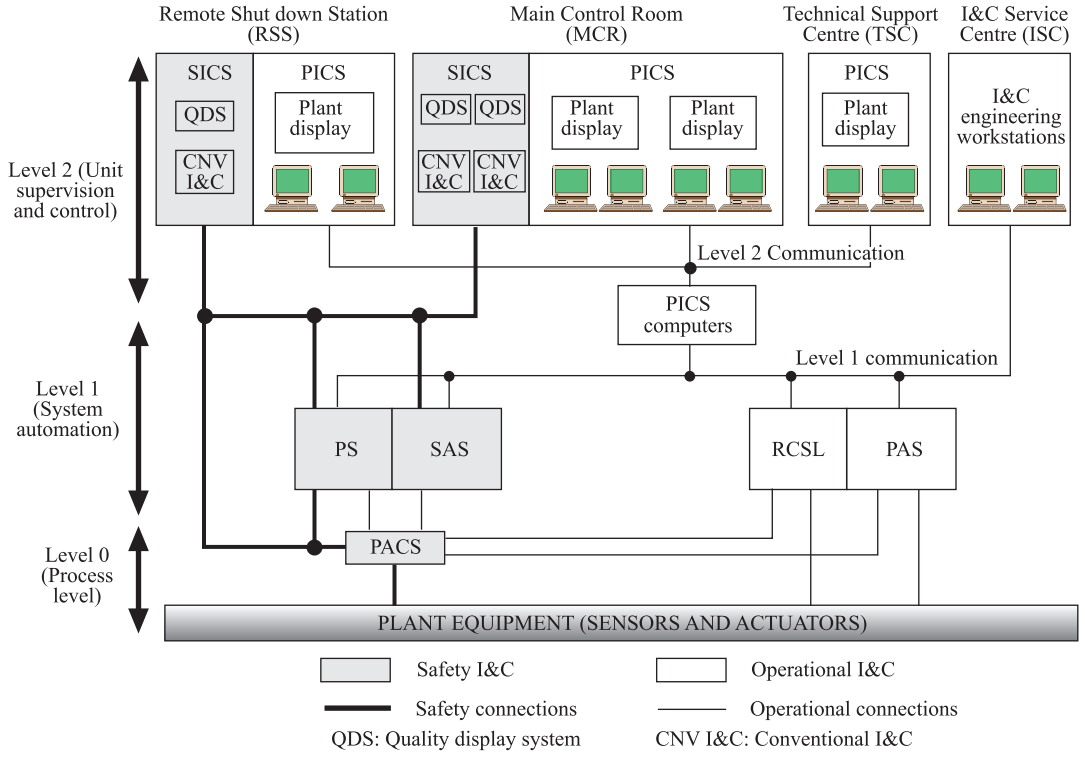


Figure 6.14 Digital instrumentation and control system—Nuclear power plant.

6.7.2 Safety Related Systems

PACS, PS, SAS and SICS are grouped under safety-related systems.

***Priority actuation and control system* (*PACS*)**

Both safety-related and non-safety-related actuators are monitored and controlled by PACS. One PACS module is allotted for one actuator. The PACS module receives and processes all commands

to control an actuator. The input signals from status and health monitors are also included for controlling the actuator. When there are many commands at a time, the module has to prioritize and respond to the highest priority command.

Protection system (PS)

It is a digital system located in dedicated cabinets and is provided with redundant power supplies. The PS is also made functionally independent of all other systems. It has its own diagnostics system. The primary function is to bring the plant to a controlled state in case of emergency. Tripping the reactor, performing emergency feed water system protection and control, actuating emergency core cooling system, actuating containment isolation and initiating anticipated transient without scram mitigating are some of the actions performed by the PS.

Safety automation system (SAS)

SAS receives signals from plant instrumentation and switchgear, processes the data, sends actuation signals either directly or through PACS, and sends monitoring signals to the SICS and PICS. The SAS functions include normal and post-accident automatic and manual control, and measuring and monitoring functions needed to bring the plant to the safe shut down state. The automatic initiation of instrumentation and control functions to prevent spurious actuations, and hence, accidents is also taken care of by SAS.

Safety information and control system (SICS)

SICS is basically a support system for short duration when PICS is not available. It controls certain safety-related support systems, like component cooling water system and ventilation. It can also be used to monitor and control the plant for a limited time in steady-state power operation. The SICS consists of conventional instrumentation and control systems and a series of Qualified Display Systems (QDSs). Non-safety-related information can also be displayed by SICS. The SICS controls are generally deactivated during normal operation of the reactor to reduce the risk of spurious actuations.

6.7.3 Non-safety-Related Systems

PAS, RCSL and PICS are grouped under non-safety-related category.

Process automation system (PAS)

The PAS takes care of mainly steam generator, turbine and heat exchanger related instrumentation and controls. The PAS controls non-safety-related systems, and also contains some backup functions for reactor trip.

Reactor control, surveillance, and limitation (RCSL) system

Necessary automatic, manual, and monitoring functions of main reactor and nuclear steam supply system parameters are executed by RCSL. Deviation of these parameters from desired values will be taken care of by RCSL before they go to tripping level. This action tends to reduce reactor trips.

Process information and control system (PICS)

The PICS uses computers, VDUs (visual display units) and soft controls to monitor and control the plant under any plant conditions. The PICS components include the following.

(a) Displays at the operator workstation at Main Control Room (MCR)
(b) Plant overview display in MCR
(c) Displays for monitoring and control at Remote Shut down Station (RSS)
(d) Displays for monitoring at Technical Support Centre (TSC)
(e) Printing, recording and archiving stations.

Plant annunciation system is also a part of PICS to give audio-visual alarm during abnormalities in the processes. Operator may take the guidance and perform appropriate corrective actions.

6.7.4 Man-Machine Interface System (MMIS)

The MMIS has mainly four interface units namely Main Control Room (MCR), Remote Shut down Station (RSS), Local Control Stations and Technical Support Centre (TSC).

Main control room (MCR)

The plant is supervised and controlled from the MCR during normal operation. The MCR is provided with essentially identical operator workstations consisting of PICS-driven screens (VDUs) and soft controls. The plant overview panel consisting of several large PICS-driven screens, the safety control area with the SCIS displays and controls, fire fighting controls and closed circuit TV monitoring screens are the additional equipment included in the MCR.

Remote shut down station (RSS)

In case the master control room becomes inaccessible, the operators can control the plant from the remote shutdown station. Manually-actuated switches for disconnecting MCR, operator workstations with VDUs and communication equipment are the parts of RSS. The operators will be able to monitor the plant conditions, and can bring the plant to safe shut down if required.

Local control stations

The operators may be able to control the processes through local control stations provided in the field itself very near to the actuator/valve to be operated. This option is normally availed during maintenance, and sometimes when both MCR and RSS are not available.

Technical support centre (TSC)

In the event of an accident, the technical support centre is utilized by the technical team. It helps to analyse the plant conditions and supports post accident management. Plant information is accessed through PICS. Process control functions are performed from TSC.

6.7.5 Instrumentation and Controls Architecture Platform

Many subsystems within overall instrumentation and control systems are implemented with some platform. Some are exceptions and implemented hard wired. The basic building blocks can be grouped into—system hardware, system software and application software categories.

System hardware

It uses a processing computer module including RAM for execution of programs, flash EEPROM for storing program code, and EEPROM for storing application program data.

System software

A set of quality-controlled software components is parts of this system. The execution of the software centres on the operating software system. The operating system communicates with the platform software and application software.

Application software

The application software normally performs plant-specific safety-related functions using function block modules. The application software is generated by specification and coding environment tools that use qualified software modules from a function block library to construct a specific application.

6.8 RADIATION PROTECTION AND MONITORING

Isotopes of uranium, plutonium and thorium are the major constituents of nuclear fuel and are radioactive. A highly radioactive mixture of fission products is generated during the fission process. The alpha, beta and gamma radiations emitted during the process pose a serious health hazard. Precautions are to be taken for the protection of the employees working in the plant as well as for the people living in the vicinity of the nuclear power plant.

The seriousness of the radiation hazards on human race is understood very clearly by NPP operators after the three major accidents that took place in Three Mile Island, USA; Chernobyl, USSR; and Fukushima, Japan. Why one should concentrate more on radiation protection and monitoring while designing a NPP can be thoroughly understood by going through the events of those three accidents. [The incidents are very briefly given in the following paragraphs].

6.8.1 Accident at Three Mile Island, USA

The nuclear power plant at Three Mile Island, Hanisburg, Pennsylvania, USA had three reactors working at the time of the accident in Reactor-2 during March, 1979. Though there was a partial melt down of the nuclear fuel rods, the chamber holding them did not rupture. Even then the clean-up work took about 14 years and costed more than one billion American dollars. The other two reactors that continue to operate at the site are set to be decommissioned in 2014.

On March 28, 1979 at 4.00 a.m., the unit-2 was operating at 97% capacity with all automatic control loops in position. Maintenance crew was working on a recurring minor problem of resin pipe chokage in demineralizer, Refer Figure 6.15 (item14). While flushing the pipe with water, a cup full of water entered the control air line which in turn initiated the control mechanisms to close outlet valves of the dimeralizer. With water flow interrupted, condensate booster pumps turned off. This caused shut down of main feed water pumps as well as turbine. As a consequence, the auxiliary feed water pumps were started. As the turbine was down, there was no outlet for the heat generated by the fission process in the reactor core. Hence, the pressure in the reactor rose, pressure-relief opened and control rods lowered to stop the fission process automatically. Then

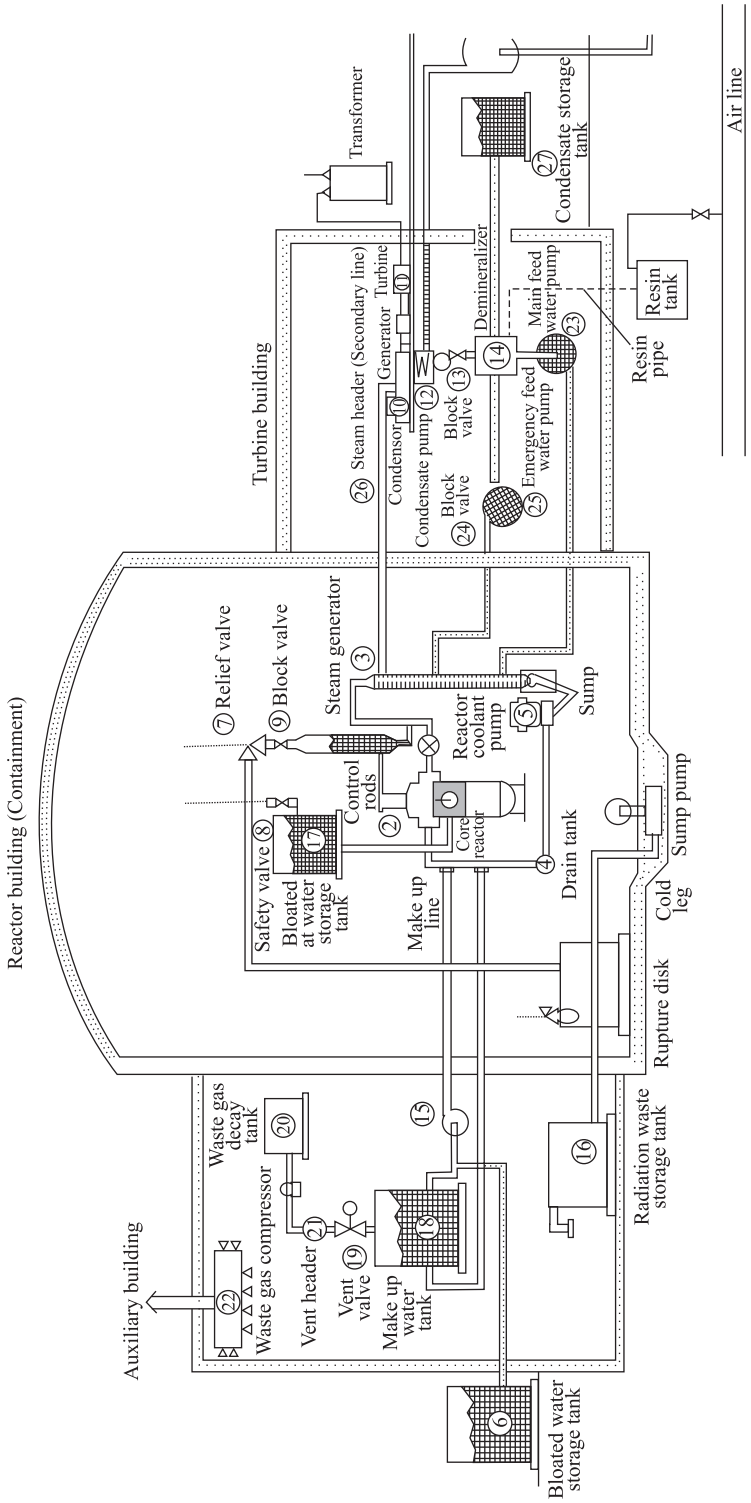


Figure 6.15 Three Mile Island Nuclear Plant Unit-2.

the pressure got reduced, solenoid valve of the pressure-relief valve got de-energized, but the valve got stuck-up and did not close. Control panel in the control room indicated as though valve was closed since it took the signal from the de-energizing action of the solenoid. Also, the auxiliary pump could not supply water as the block valve was left closed by mistake after maintenance work sometime back. Because of the above events, the steam generator started boiling dry. There was no heat removal from the reactor as the steam turbine was already down. Loss of water through relief valve made other emergency pumps to operate. Also, full emergency core cooling system went into operation because of low pressure of the reactor. Low reactor pressure caused steam bubbles formation and showed virtual increase in water level in the control room. Operators misinterpreted the level as actual and stopped emergency pumps allowing very less water. Water was escaping through relief valve without operator's knowledge. Operators started draining water manually, thinking that water level is high. Suddenly, there was a pressure drop. Because of the above happenings, steam bubbles in the reactor water started covering much of the fuel. Hence, the top of the fuel rods started crumbling.

At this juncture, chemical reaction between the steam and zircaloy covering the fuel elements took place. This caused hydrogen production resulting in explosion of the containment structure. By this time two hours have passed after the initial event. Next shift people arrived for duty. As they were very fresh, they could identify the blocking valve in the relief valve line problem and closed it manually. But it was too late by then. All staff members excepting emergency staffs were evacuated. After about thirteen-and-half hour reactor was brought under control. But damage was already done. Clean up action alone took many years, and costed more than a billion dollars. Three Mile Island was a financial disaster. It exposed the lack of emergency preparedness at both the reactor site and evacuation-planning centres.

6.8.2 Disaster at Chernobyl Nuclear Power Plant, Ukraine (Then USSR) (refer Figure 6.16)

Chernobyl, near Kiev, Ukraine (then USSR) had a nuclear Power Plant of 4000 MW capacity, with 4 units each with 1000 MW capacity, and had an expansion plan for two more units. The reactors were of RBMK type with graphite moderators and boiler water pressure tubes. On April 25, 1986, a test was being conducted on reactor-4 to decide how long the mechanical inertia of the turbine generator rotating mass keeps the generator running after shutting off the steam supply. The test was undertaken as a part of a scheduled plant shut down. Thermal heat power was slowly reduced to about 700 MW from 1000 MW as planned. In preparation for the test, the operator had disconnected the emergency cooling system thinking that the power consumption by the system might affect the test results. This action was considered certainly a safety violation. The test had to be discontinued because of the instructions from the power despatch centre to satisfy an unexpected demand. After about ten hours, the clearance was again given to carry on the test. An error occurred when the controller was reprogrammed to maintain the heat power at 700 MW from 1000 MW. The output dropped all the way to 30 MW and the reactor became uncontrollable. Instead of shutting down the unit, the operators tried to continue the test, and hence, raised all control rods. Fifteen rods should have remained inserted as per norms. But this had to be done because the fuel got poisoned at low power level by a buildup of xenon-135 which absorbs neutrons. Even after raising all control rods, the power could be increased only up to 200 MW.

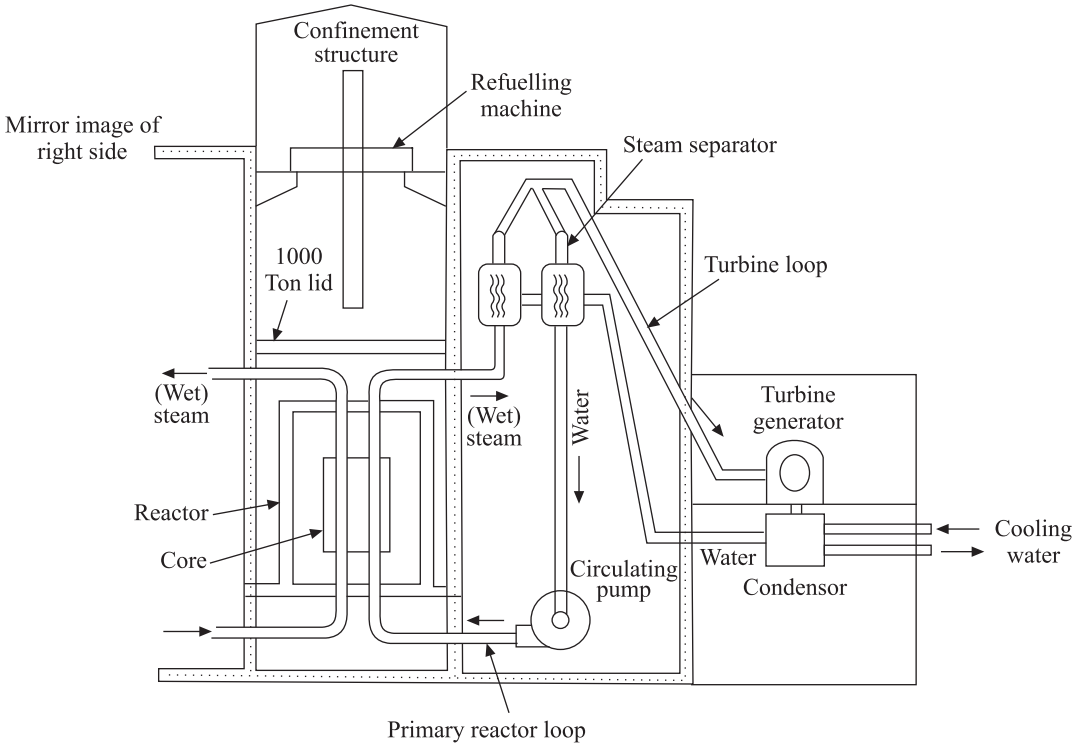


Figure 6.16 Schematic diagram of Reactor-4 at Chernobyl.

As it became difficult to control the reactor automatically, the operators by-passed so many safety controls and started manual operation. This wrong decision was taken to avoid delay due to shutting the unit down and bringing it back. The reactor was now running free, isolated from outside world, its control rods out, and its safety systems disconnected. When steam valves were closed and its load effectively removed, the reactor's power and temperature rose sharply. When core became hot, fission increased, core became hotter and this positive feedback produced heat power hundred times its rated thermal power.

The fuel did not have time to melt, but simply shattered into fragments. The fragments came in contact with water causing heavy explosion. The explosion lifted and shifted the 1000 ton concrete floor. The zirconium cladding of the fuel rods interacted with circulation water to generate hydrogen which acted as fuel. This produced a spectacular display of fireworks. A shower of glowing graphite and fuel spread all over the compound while a radioactive plume was driven sky-high by the heat. Valiant fire fighters lost their lives. It took hours to warn the surrounding communities. Alert Nuclear Power Plant operators in Sweden detected an increase in radio activity, and alerted Russia as well as the rest of the Europe. Total deaths attributable to Chernobyl accident ranged as high as 10,000. Many more got affected by acute radiation sickness. About 1.5 lakh people had to be relocated. Even drinking milk, eating vegetables, letting children play outside, etc., were restricted. Reactor was covered with concrete materials. Tunnels were dug and liquid nitrogen piping installed for cooling.

6.8.3 Calamity at Fukushima, Daiichi Nuclear Power Plant, Japan

The approximate layout diagram of Fukushima Nuclear Power Plant is shown in Figure 6.17. The reactor-1 went critical during March, 1971, with a rated capacity of 460 MW. Unit-2 and unit-3 with 780 MW each went critical in July 1974 and March 1976, respectively. Unit-4 was added later on and unit-5 and unit-6 afterwards with a capacity of 900 MW each. The total rated capacity of the plant works out to be 4700 MW. All the reactors were Boiler Water Reactors (BWRs). Main offices and storage for spent fuel were located in between the group of reactors 1 to 4 and the group of 5 and 6.

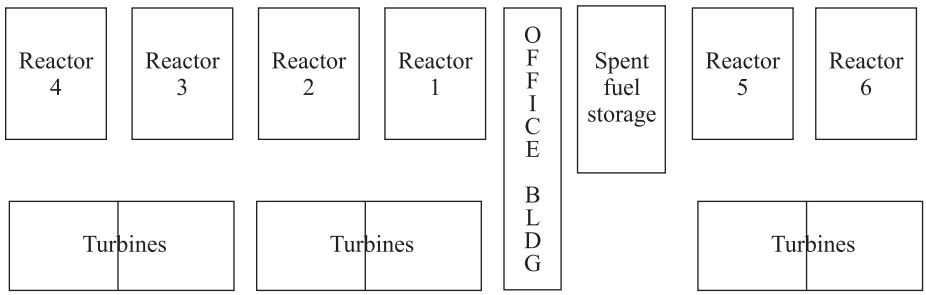


Figure 6.17 Layout of Fukushima, Daiichi, Nuclear Power Plant, Japan.

On March 11, 2011 an earthquake of magnitude 9 (nine) in Richter scale struck near Fukushima sparking tsunami. The tsunami knocked out the generators that produced the power. Lack of power in turn caused the cooling systems of the reactors to fail. Even the emergency diesel generators failed after an hour's operation. Since a very high amount of heat is generated in the reactor, the flow of the coolant should never be disrupted. Though the power producing fission process stopped by using control rods that absorbed the neutrons immediately after the quake, the fuel still contained fission products, such as iodine-131 and caesium-137, and activation products, such as plutonium-239. These radionuclides continued to produce heat during the decay period. There is no way of stopping radioactive decay of the fission products.

Apart from the original heat, the heat produced continuously by the fission products and activation products could not be removed even after the uranium fission process was stopped. Inability to remove this heat led to a rise in coolant temperature. When the temperature reached around 1000ºC, the zirconium alloy that encased the fuel (cladding) began to melt or split apart. In the process, it reacted with the steam and created hydrogen gas which is highly volatile. Though the pressure created by hydrogen gas was reduced by controlled release, the massive build-up of hydrogen led to the explosion that blew the roof of the secondary confinement. Sea water was pumped in to avert full scale nuclear meltdown. The use of boric acid, an excellent neutron absorber, was tried. Despite these measures, the fuel rods were found exposed in unit-2 on two occasions. Whatever led to a decrease in water level, the spent fuel storage pond caught fire possibly due to hydrogen explosion. The radio activity was released directly into the atmosphere. Radioactivity of about 400 millisievert/hour was reported at the site immediately after fire. This level of radioactivity is well above the safe level of 1 millsievert per week

About two lakh people were evacuated from 30 km radius around plant. Within four days after the earthquake and the followed tsunami blasts in reactors 1, 2, 3 and 4 were reported. Cooling

problems in reactors 5 and 6 were observed. All six reactors at the complex had problems: be it blown out roofs, potentially cracked containment structures, exposed fuel rods or just the risk of explosion. It is estimated that the eventual clean up may take more than 10 years. A global experts team estimated that it would take at least three decades to return the site to what engineers refer to as a green field state. There are also billions of dollars likely at the stake in the clean-up.

The scale and complexity of the challenge is unprecedented. No nuclear reactor has ever been fully decommissioned in Japan, let alone the four reactors certain to be dismantled at Fukushima, after being flooded with sea water to avert meltdowns, and after suffering explosions and other damage. The final fate of the reactors 5 and 6 has not been announced, but they too may need to be decommissioned.

The accident at Three Mile Island, USA, in 1979, involved just one reactor, and though there was partial meltdown of the nuclear fuel rods, the chamber holding them did not rupture. The clean-up there still took 14 years and costed more than a billion dollars. The two more reactors that continue to operate at the same site are set to be decommissioned in 2014. Thus, the Fukushima episode has eclipsed the Three Mile Island accident.

But in expert's view Fukushima is not a Chernobyl. The Chernobyl accident in Ukraine in 1986 was the worst in the industry's history, as explosions led to a cloud of radioactive material being spewed over many parts of Europe. Following the multiple explosions and fire that sent huge radioactive plumes into the atmosphere, workers covered the remains of the reactor with sand, lead, and eventually entombed it with concrete to halt the release of radiation. The concrete coffin still remains at Chernobyl, and the area remains uninhabitable.

Since the complete report is still not available it is very difficult to express the magnitude of the Fukushima accident. Several experts feel that the Japanese authorities are underplaying the severity of the incident.

6.8.4 Radiation Units

Roentgen is the unit used to measure the extent of ionization produced by gamma rays or X-rays.

Definition

Roentgen (r) is the quantity of radiation which produces a charge of ions of either sign of one electro static unit (cgs) in traversing a volume of 1 cm^3 of pure air at standard temperature and pressure (= 0.001293 g at 0ºC, and 760 mmHg)

or

Roentgen (r) is the quantity of radiation that will produce, as a result of ionization, electrons carrying a total charge of 2.58×10^{-4} C in 1 kg of dry air.

Roentgen (r) is the unit of radiation exposure.

The radiation dose or the absorbed dose is expressed in terms of the amount of energy absorbed by a material by ionization radiation. The unit for radiation absorbed dose called the 'rad'.

'Rad' is defined as the amount of radiation that leads to the absorption of 10^{-2} J of energy per kg (or 100 ergs per gm) of the absorbing material.

Gray (Gy), the SI unit of absorbed dose, is defined as the absorption of 1 joule of energy per kilogram of material.

Therefore, 1 Gy = 100 rad

The 'rad' is applicable to ionization radiation of all kinds, including gamma rays and X-rays, whereas 'roentgen' is applicable for gamma rays and X-rays only. However, the exposure of 1 roentgen results in the deposition of 0.96×10^{-2} J/kg of soft body tissue. Hence, the exposure in roentgens and the absorbed dose in soft tissue in rads can be assumed equal numerically. While considering the safety of human beings, the exposure or dose has to be expressed over a period of time. The rate at which the radiation is received becomes important. Accordingly, the exposure rate is expressed in terms of roentgens per unit time and the absorbed dose rate in rads per unit time. The permissible limits of accumulated absorbed dose for the human beings are given as follow:

- 0.1 rad a week
- 3 rads in 13 consecutive weeks (per quarter)
- 5 rads in an year

The biological effect depends not only on rads absorbed but also on other factors. The effect is expressed interms of the 'Dose Equivalent', the unit being rem (or radiation equivalent in man). The Dose Equivalent (DE) in rems is defined by the equation.

$$DE\ (rems) = D(rads) \times QF \times MF$$

where

QF = Quality factor for the given radiation
MF = Modifying factors

'Sieverts' (Sv) is the equivalent unit in SI units for 'rems' with reference to the absorbed dose in grays (Gy)

1 Sievert (Sv) is thus equivalent to 100 rems

For all practical purposes in NPP, MF is assumed as unity for external radiation exposures, but QF = 1 for electrons and all electromagnetic radiation,

QF = 10 for fission neutrons and protons
QF = 20 for alpha particles, heavy recoil particles, and fission fragments

6.8.5 Biological Effects of Radiation

Radiation exposure can be classified into three categories:

1. Acute exposure: Large dose of radiation received in short duration (a day or less).

2. Chronic exposure: Continuous exposure to moderate or small doses of radiation.

3. Semi-acute exposure: Intermediate between acute and chronic with respect to magnitude and time.

Acute and semi-acute exposures are experienced in Nuclear Power Plant only during the unlikely event of a serious accident. During normal operation chronic exposure only is expected.

There are two categories of cells in living organisms, namely somatic cells and germ cells. Somatic cells are present in all parts of the body, whereas the germ cells are formed in sex glands. Observable effects can be seen in the exposed individual if somatic cells are injured. They are

called somatic effects. Injuries to germ cells can cause genetic effects. The genetic effects may become apparent in latter generations.

Somatic effects of radiation

The somatic effects may be categorized into two varieties, namely early effects and delayed effects.

1. Early effects: These may appear within a few minutes to several days depending on the magnitude of the dose. It is caused mostly by acute and semi-acute exposures. Chromosome aberrations and decrease in white cell level may be observed if the acute dose is in the order 5 to 75 rems. Vomiting with fatigue and loss of appetite is expected when the dose level is about 75 to 200 rems. Recovery is possible in a few weeks. If the exposure is in the range of 200 to 600 rems severe vomiting, blood changes, hemorrhage and increased susceptibility to infection occur to the person exposed to. Survival rate is only 20% at the upper end of the range. When the exposure is 600 to 1000 rems, severe blood changes, hemorrhage, infection and loss of hair happen. Survival is difficult. The early effects are not observed in case of chronic exposure at sufficiently low dose rate.

2. Delayed effects: Eye cataracts and the induction of various types of cancer are the major delayed somatic effects of radiation following acute and semi-acute exposures. Leukemia attacks in two years time, whereas other types of cancer may appear even after 15 years.

Genetic effects of radiation

Mutations (changes in germ cells) occur spontaneously at a significant rate. Mutations caused by ionizing radiations in either the egg or the sperm will be passed onto subsequent generations. Mutations are considered to be detrimental ranging in severity from negligible to lethal. The potential genetic effects accumulated over the years preceding reproduction has to be considered in setting radiation dose limits for occupationally exposed workers, and for the population living in the vicinity of the nuclear power plant. Chromosome abnormalities and changes in genes which make up the chromosomes are normal genetic effects caused by radiation doses. Point mutations are considered to be more important.

6.8.6 Radiation Monitoring

Radiation monitoring has to be done extensively to protect the people working in a Nuclear Power Plant, and those living in the vicinity. The monitoring results are supposed to provide assurance to them that they are safe from the radiation effects. The monitoring operations are normally divided into following categories:

1. Personnel monitoring
2. General monitoring
3. Fixed area monitoring
4. Radiation survey
5. Monitoring of coolant and effluent systems
6. Environmental monitoring

Ionization chamber and proportional counter types were already discussed in Section 6.5.2. In addition, some more kinds of monitoring devices are used in Nuclear Power Plants. The different categories of monitoring with monitoring devices used are as follows:

Personnel monitoring

Every individual working in a reactor facility must use personnel monitoring device called dosimeter, for measuring the radiation doses received over a period of time. The commonly used dosimeters are: Photographic-film dosimeter or film badges, Pocket ionization chambers or pocket meters, Thermo Luminescent Dosimeters (TLDs) and Radio Photo Luminescent Dosimeters (RPLDs).

1. Film badges: Ionizing radiation generates an effect on photographic film similar to that of light. After the exposure to radiation, the film is developed to find out the extent of the blackening in film which is a measure of total amount of radiation to which the film is exposed. Film badges are available which are sensitive to beta, gamma and neutron doses. A frame made up of either plastic or metal holds the film in a light-tight wrapping. The frame with a clip can be attached to the exterior clothing of the person using it. Everyone working in the vicinity of the reactor is supposed to wear it. One may be allotted two or more badges so that when one badge is send for analysis to a certified agency, the other one can be worn. They are allotted to a specific person and not to be interchanged. The cumulative dose can be accounted for a particular period to get satisfied that the cumulative one is within safety limits.

2. Pocket ionization chambers (Pocket dosimeter): The size of this meter may be as that of a big fountain pen so that it can be kept in the pocket of the person who is likely to get exposed. A cylinder of plastic material lined with graphite is the positive electrode, whereas a stout wire runs axially through the cylinder serves as the negative electrode. The electrodes are charged to a known voltage say about 150 V. The voltage will remain unchanged as long as there is no radiation exposure. The change in potential measured at the end of the day is proportional to the dose received. Pocket dosimeters measure gamma radiations and beta radiations. They can be made to measure thermal neutrons also with boron lining. Pocket dosimeters are simple to read and recharge, cheap and can be used frequently. Somewhat costlier version is the self-reading pocket dosimeter, where the inner electrode is a short wire attached with a flexible, metal coated quartz fiber. The position of the quartz fiber on a calibrated scale gives the radiation dose received.

3. Thermo Luminescent Dosimeters (TLDs): Thermo Luminescent Dosimeter has better accuracy than that of film badge dosimeter, but the initial cost is somewhat greater. It has other advantages like repeated use, greater resistance to the environment and long shelf life. When the Thermo Luminescent is exposed to ionizing, radiation free electrons are generated. They are trapped at unstable centers in the crystal lattice. When the material is heated the trapped electrons return to normal state. While returning, they emit visible light proportional to the dose absorbed. The materials suitable for TLDs are lithium fluoride, lithium borate, calcium fluoride, calcium sulfate, and beryllium oxide.

4. Radio Photo Luminescent Dosimeters (RPLDs): The radiation detector material here is a phosphate glass activated with silver. Stable flurorescing centers are formed when exposed to ionizing radiation. These centers emit visible light when irradiated with ultraviolet light subsequently. The amount of visible light emitted is proportional to the amount of radiation energy absorbed by the glass. The amount of light emitted is measured with the help of photomultiplier tube or by a fluorimeter with orange filter.

Digital dosimeter uses a Geiger Müller (GM) tube along with solid state circuit for digital read out. Sometimes, personnel survey is done by monitoring the individuals leaving an area from where they must have got exposed to radiation. Such an instrument invariably consists of G-M tubes with associated counting meters.

General monitoring

General area monitoring is carried out with the help of ionization chamber for fairly high radiation levels and G-M counter and scintillation counter for low level radiation. Neutron detection is done by proportional counters.

1. Geiger-Müller (G-M) counters: Geiger-Müller (G-M) counter operates in Geiger region in Figure 6.3 where the applied voltage is high at 800 to 1200 volts. It is also an ionizing device, like ionization chamber and proportional counter. The collecting electrode is a central wire anode surrounded by a cylindered cathode. An electrical pulse is produced for each ionizing particle entering the tube. The pulses are fed to an electronic circuit to indicate the counting rate as a current measurement. The current is proportional to the radiation exposure rate. The instrument can be calibrated to read in milliroentgens (or milli rads) per hour.

2. Scintillation counters: Radiations cause electronic excitation in many solids and liquids in addition to ionization. In sodium iodide, lithium iodide and cesium iodide crystals containing small amount of thallium, the excess energy of the electrons is emitted within a short time as a flash of light. If the light is allowed to fall into a photomultiplier tube, a pulse of appreciable voltage corresponding to each radiation particle is produced. The pulse or pulse rate can be measured as equivalent to exposure or dose rate. Compared to G-M counter, it is more sensitive, more accurate and can be used for much higher counting rates. But it is more expensive and less rugged. A typical arrangement with electronics involved is shown in Figure 6.18.

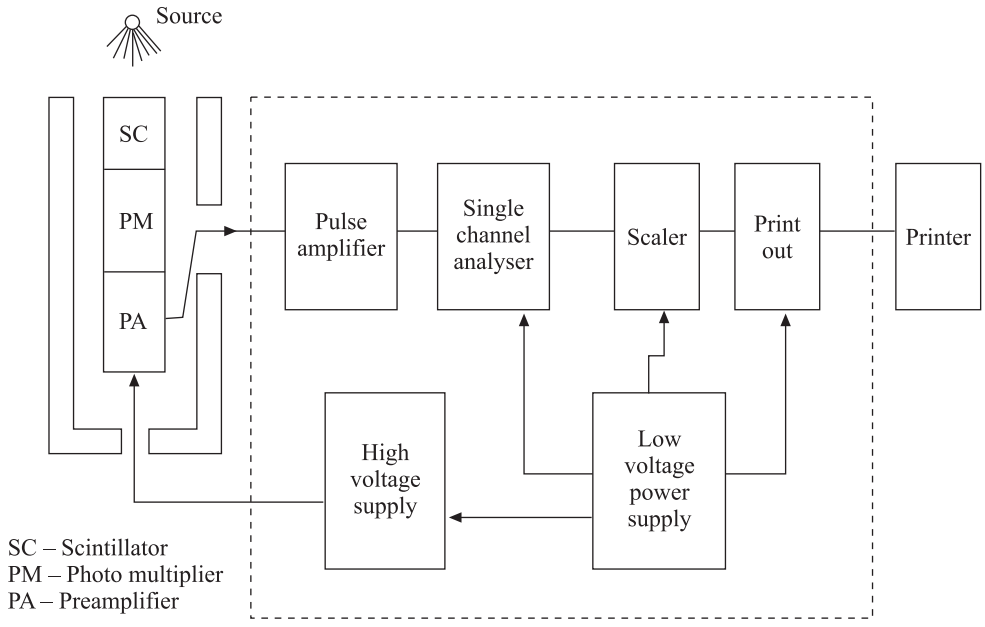


Figure 6.18 Typical arrangements of electronics—Scintillation counter.

Fixed area monitoring

Monitoring instruments for gamma rays are installed at fixed locations where such radiations are expected in a nuclear power plant. Neutron monitors are located in and around the reactor vessel proper. These meters indicate in the location where they are fixed and also transmit the signals to control room where all such locations can be monitored centrally. Audio visual alarms are also provided whenever the dose rate exceeds the prescribed limit. Continuous Air-particulate Monitors (CAMs) are located at different locations in the nuclear plant to determine the radio activity of particulate matter in the air. Ionization chambers, G-M counters or scintillation counters are used for the above purpose.

Radiation survey

To survey areas where people are working when the nuclear plant is either in normal operation or in refueling operation, portable instruments are used. Such instruments must be compact and easily movable, should respond rapidly and give indication as well as audio visual alarm. The instrument is selected depending on the nature of the radiation, magnitude of the radiation and the type of information (qualitative or quantitative) required.

G-M survey meter is commonly used for low levels of beta and gamma radiations. It is employed for general survey of personnel, clothing, tools, protection equipment, etc., and in decontamination operations. G-M tube is kept in a probe encloser with a cable connected to the reading instrument box. While transporting they can be separated. The portable instrument box contains low-voltage batteries, DC-DC converter etc to generate the high voltage required for the G-M tube.

Neutron instrument with proportional counter is used for detecting slow neutrons. The proportional counter contains boron trifluoride enriched with boron-10. The counting circuit is adjusted for not responding to beta and gamma radiations. The proportional counter without boron trifluoride, but lined with paraffin can be used for detecting fast neutrons. Scintillation counters are used for the detection of both fast and slow neutrons.

Monitoring of coolant and effluent systems

Both primary and secondary coolant system of PWR and steam carrying pipes of BWR are continuously monitored for gamma radiation. This will serve the purpose of finding out defects in fuel-element cladding, and in the steam generator tubing. G-M counter, scintillation counter and sometimes pulse-type ionization chamber are generally used. The final read out is normally displayed in the control room to keep the operator informed of the radioactivity level all the time.

Liquid and gas effluents from the rad waste system are tested before discharging. Liquid effluent is normally tested in the laboratory taking samples. Gaseous effluents are checked on a continuous basis. The effluents from various parts of rad waste system are mixed with large quantity of clean air or water before discharging to the surroundings. Quantitative measurements are required as the effluents enter the nearby water body or atmosphere. Pulse-type ionization chamber or scintillating counters are used here as G-M counters are not sufficiently accurate for this purpose.

Environmental monitoring

Before the Nuclear Power Plant is taken into operation, radiological survey of the area conducted and established a basis for comparison when the plant is operating. The duration of the testing

may last for about two years. During that period, samples are taken periodically from air, water, soil, river, vegetation, milk, fish, etc. Analyses of these samples are done in the laboratory for their radionuclide content. Ambient radiation levels are measured with the help of dosimeters at various distances and directions from the nuclear installation. Similar monitoring programme is continued when the plant starts operating.

6.9 NUCLEAR REACTOR SAFETY

Highly radioactive and potentially hazardous fission products are generated during the operation of the nuclear power plants. Hence, the concern for safety is an essential aspect of engineering design. Greater emphasis is normally given for safety aspects. Otherwise failures can have serious consequences as happened in Three Miles Island, Chernobyl and Fukushima Nuclear Power Plants (Refer 6.8.1, 6.8.2 and 6.8.3). To assure the safety of the people working in the plants and the public living in the vicinity of the plants, stringent measures are required in the design of nuclear reactor installations. In addition, safety and protection systems are to be incorporated to safeguard the people and the plant not only from human errors and equipment failures, but also from the effects of natural calamities, like earthquake, tsunami and tornadoes.

Redundancy principle of design is generously applied while designing protection systems. It means the use of two or more similar systems in parallel so that the failure of one will not affect the operation as the second one takes care of the operation immediately. Redundancy principle is given much more importance in systems, like instrumentation and controls, shut down controls and emergency cooling, on which safety plays a very important role.

6.9.1 Reactor Protection System

The thermal power generated by the reactor by fission process is used to make up the steam demand by the turbo-alternator. Whenever the electrical load, and hence, the steam demand varies, the reactor control system with automatic and manual controls respond to meet the change in demand, but maintain safe operating conditions. Generally, excess cooling capacity to the extent of about 120 per cent is taken care in the design itself. Whenever the thermal power exceeds the limiting value due to abnormal conditions, there should be provision in the reactor protection system to trip the reactor. Also, transients may happen to some of the important parameters, like system temperatures and pressures, coolant flow rate, thermal power level, etc. When the transient is minor and within the permissible limits, the controls should take care. However, for severe transients the reactor protection system should get activated. The purpose of the protection system is to safeguard the reactor from damage due to overheating caused by severe transient of important parameters or malfunctioning of equipment. A wide variety of instruments are used for measuring operating parameters of the Nuclear Power Plant. When instruments indicate transients that cannot be corrected by the control system, the reactor is shut down automatically by the protection system. Manual tripping option is provided to the operator for use in case there are indications that an unsafe condition is developing.

6.9.2 Reactor Tripping

The electromagnetic (solenoid) clutches holding the control rods are reenergized whenever the trip signal is received either by automatic mode or by manual mode. In case of PWR, the control

rods drop into the reactor core, and in case of BWR, the control rods are forced up into the core by hydraulic pressure. An important aspect is that the protection system must not fail when needed and should not cause unnecessary trips (false trips). Redundant monitoring helps to avoid false trips. Only when two or more signals call for action simultaneously, the reactor trip will occur. The signals which can cause the actuation of the protection system to trip the reactor are as follows:

1. Rapid increase in the neutron flux during start up causing rapid rise in thermal energy in the reactor
2. High level of neutron flux than the permissible one during power operation
3. Abnormal reactor system temperature
4. Abnormal reactor system pressure
5. Loss of coolant flow (or coolant pump failure)
6. Higher steam flow than required by turbine
7. Closure of main steam isolation valve
8. Alternator trip due to loss of load
9. Loss of power to instruments, pumps etc.
10. High water level in the pressurizer (for PWR)
11. Low water level in the reactor vessel (for BWR)
12. Low water level in the steam generator (for PWR)
13. High radio activity in the steam (for BWR)

6.9.3 Engineered Safety Features

In cases of severe transient or accident beyond the control limits of reactor protection system, there will be escape of radio activity to the environment. Such an escape of radioactivity has to be prevented by special features which are to be engineered beforehand. In general, such features can be classified into three categories:

- Emergency core cooling system
- Containment vessel
- Prevention of formation of explosive mixture

Emergency core cooling system

This system is required to supply water to the reactor core in the event of a loss-of-coolant accident. The system pressure drop in the primary coolant circuit will actuate the emergency core cooling system. It is proper to mention here that even emergency core cooling system which was in Fukushima Nuclear Power Plant, was washed away in the tsunami caused by the earthquake there. The emergency diesel generators provided for this purpose was in lower level than that of the tsunami waves, and hence, got broken down. In the recent nuclear units coming elsewhere in the world this aspect is also being taken care of.

The primary cooling systems are different for PWRs and BWRs. But in both cases water is supplied in large volumes and from different sources. Redundancy of emergency cooling equipment and water flow paths is provided. Emergency cooling systems normally provided for PWR and BWR are discussed separately.

1. Emergency core cooling system for PWR: When the reactor system pressure drops moderately from the normal operating pressure, the High Pressure Injection System (HPIS) comes

into operation. This condition may appear due to leakage or breakage in the primary coolant circuit or due to maloperation of the pressuriser relief valve. While HPIS compensates for the loss of coolant, Chemical and Volume Control System (CVCS) pumps inject borated water into the inlet line. A slow acting backup system also injects borated water into the reactor outlets.

In the event of rapid pressure drop due to heavy leakage or breakage, the accumulator injection system will be actuated. The accumulator stores contain large amount of cool borated water under nitrogen gas. Since it does not require any pump and electricity, it is considered a passive system in the overall emergency core-cooling system.

If the pressure is reduced further, then a Low Pressure Injection System (LPIS) comes into action. Both HPIS and LPIS are active systems and require electricity for functioning. In case of electricity failure, diesel generators have to start in short time, say, 30 seconds. In case of borated water shortage, water from the sump in the containment structure is utilized.

A typical schematic diagram of an emergency core-cooling system for PWR is shown in Figure 6.19. The more severe condition is the one when the complete primary coolant flow fails. Even in such cases the water injected through emergency core-cooling system should save the reactor from getting over heated.

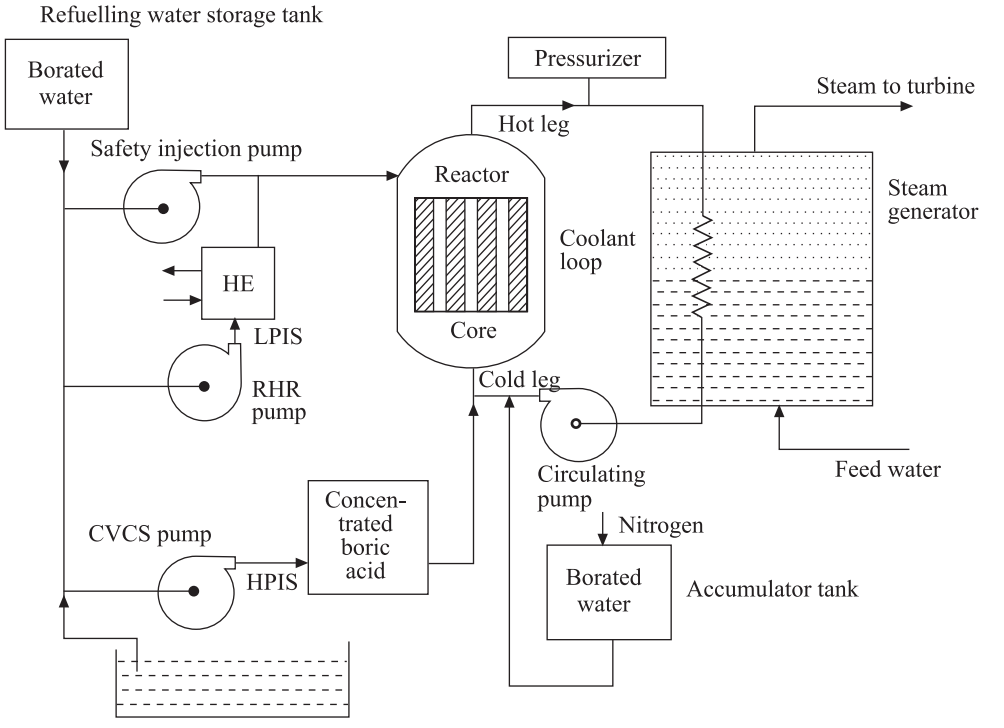


Figure 6.19 PWR emergency core-cooling system.

2. Emergency core cooling system for BWR: In BWR, the pressure drop may occur due to leakage or breakage of either water line or steam line. The rate of depressurization may not be that high as in the case of PWR. Normally, three subsystems are designed for emergency core-cooling system for BWRs. To ensure reliability, components are installed in redundant mode. A High Pressure Core-spray System (HPCS) forces water from the above and along the periphery of the reactor core through nozzles. A Low Pressure Core-spray System (LPCS) protects the reactor against rapid depressurization due to heavy leaks. A Low Pressure Injection System (LPIS) comes into operation when large volume of water is required.

The subsystems would be actuated by the system pressure signals. The continuous water supply to all the sub systems is ensured from the pressure suppression pool. This pool also collects water and steam leaked from the reactor vessel. An automatic relief valve is provided to vent steam to the suppression pond. A schematic flow diagram of an emergency core-cooling system including all the three subsystems is shown in Figure 6.20. Emergency diesel generators are provided as in PWR for taking care of the situation when regular electrical supply fails.

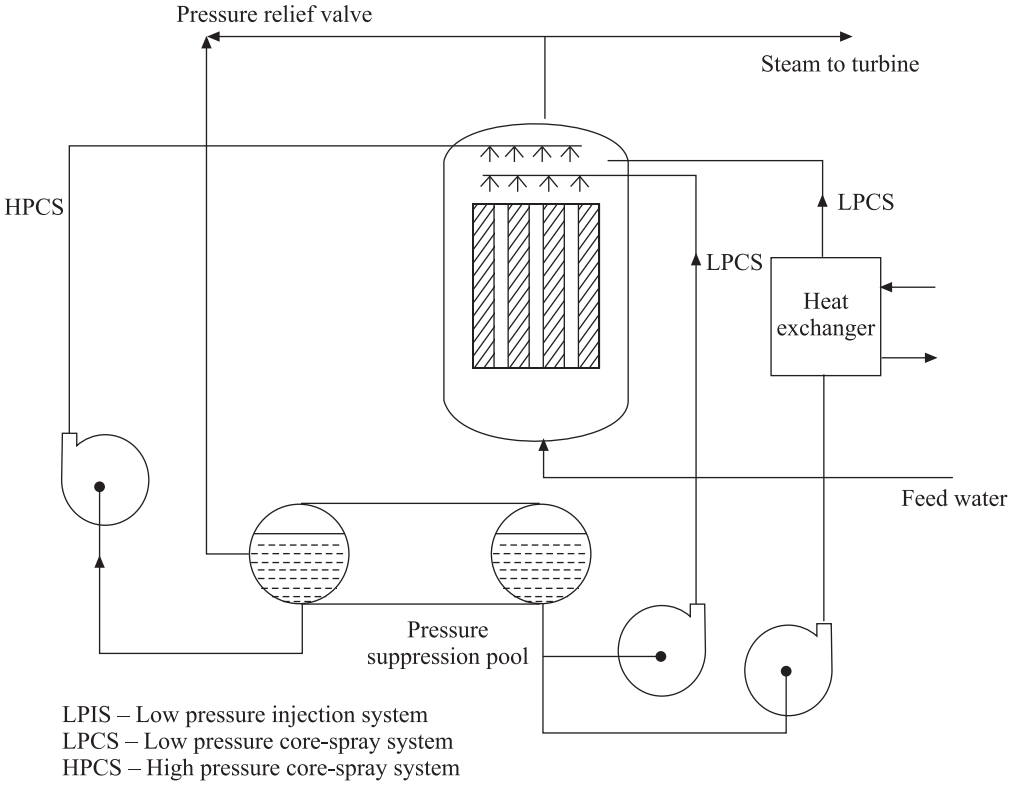


Figure 6.20 BWR emergency core-cooling system.

Containment vessel

If a sudden decrease in pressure occurs due to a severe break down, the total water in the reactor vessel will flash into steam. The coolant flow is completely lost then. In such conditions, some of

the fuel rods may be damaged and radiation may be leaked through. The containment vessel is designed in such a way that all the steam and radio activity that would escape from the reactor vessel due to loss of coolant flow may be contained in the vessel itself.

Prevention of formation of explosive mixture

Whenever the hydrogen to air ratio reaches 4:1 by volume, then there is a chance of explosion to take place. The production of hydrogen can take place due to various reasons when loss-of-coolant accident takes place. The reaction between steam and the zirconium in the zircalloy fuel cladding generates hydrogen gas and zirconium oxide. Also, the sodium hydroxide present in the containment spray used for iodine removal may interact with metals, like aluminum to produce hydrogen. In addition, gamma rays radiation causes decomposition of water into hydrogen and oxygen. Hydrogen produced, may get accumulated and reach a point where it is explosive.

The remedial measures are:

1. to purge nitrogen to render the containment atmosphere inert
2. to circulate air so that the formation of explosive mixture can be avoided and
3. to remove the hydrogen gas using hydrogen-oxygen recombiner (both catalytic and flame combiners are used for this purpose).

6.10 SURVEILLANCE, DIAGNOSTICS, AND PROGNOSTICS

Compared to conventional thermal power plants, Nuclear Power Plants require enhanced online monitoring and diagnostics for achieving high performance with safety. One has to move from periodic inspection to online monitoring for condition-based maintenance and eventually prognostics. Sensors are to be included in the list for online monitoring. Better understanding of what and how to measure within the plant, enhanced data interrogation, communication and integration, new predictive models for damage evolution, system maintenance and prognostics philosophies are the areas where advancement has to take place. Surveillance and diagnostics techniques are in use for different applications in Nuclear Power Plants. Some of the applications are instrument response time measurements, rotating machinery condition monitoring, predictive analysis of failures in sensors and impulse lines, motor current signature analysis and core barrel motion monitoring.

Initially, system surveillance and diagnostics were developed and adopted in the aerospace industry for the obvious reasons. As years pass by, these technologies were extended to process industries. After the accidents at Three Mile Island, USA and Chernobyl, USSR the emphasis and application of these technologies has increased in nuclear power plants. Though the detailed information is beyond the scope of this book, the definitions and integration of surveillance, diagnosis and prognosis modules will be dealt here.

6.10.1 Surveillance

Surveillance or monitoring of equipment, sensor or device refers to the tracking of degradation-sensitive parameters that are derived from measurements made on the specific component or subsystem. In this task it is looked for changes in the signatures of interest. Residuals between the measured process variables and their estimated values using data-driven models; various statistical

parameters, such as standard deviation, Root-Mean-Square (RMS) value, signal skewness, and crest-factor; spectral domain parameters, such as frequency bandwidth, RMS values at specified frequencies, and ratio of energies between two frequencies; and performance parameters computed from data-driven models are some of the examples of such signatures.

6.10.2 Diagnosis

The cause of changes exhibited in the various signatures during the surveillance is determined by diagnosis and the devices that indicate incipient failures are isolated then. Surveillance, fault detection and isolation require knowledge-based expert systems to identify the root cause of impending failure.

6.10.3 Prognosis

Prognosis module, the most difficult of the three modules, is concerned with the estimation of useful life of a piece of equipment. Prognosis in combination with condition monitoring is useful in planning maintenance and equipment replacement, and increasing the reliability of devices.

The integration of surveillance, diagnosis and prognosis modules is shown in Figure 6.21 as block diagram.

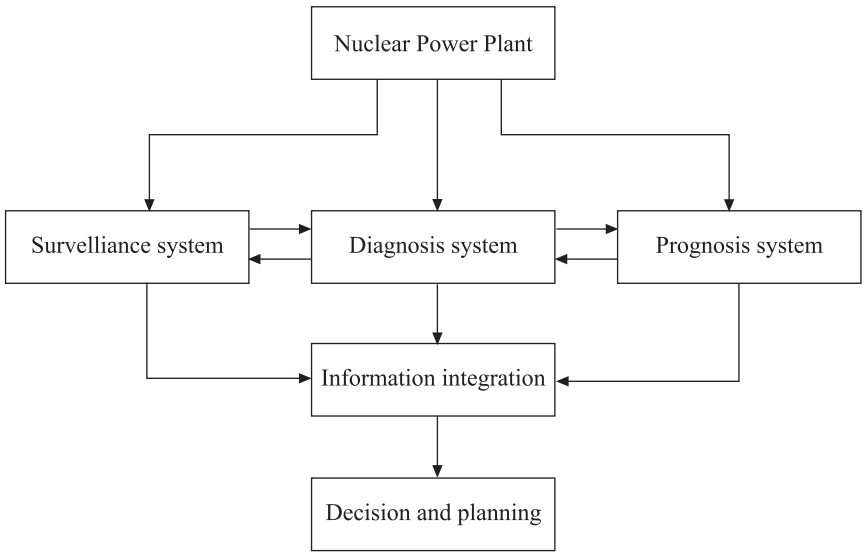


Figure 6.21 Integration of surveillance, diagnosis, and prognosis modules in a NPP.

Using the above system one can predict equipment failures and/or maintenance needs even months in advance. Verification of the performance of sensors and assessment of the health of NPP equipment can be done while the plant is operating.

WORKED-OUT PROBLEMS

PROBLEM 6.1 Calculate the number of fission per second required to generate in U^{235} nucleus.

(i) 1 W of power
(ii) 1 kW of power
(iii) 1 MW of power

Solution:

(i) The fission of a single U^{235} nucleus is accompanied by the release of about 200 MeV energy.

$$1 \text{ MeV} = 1.02 \times 10^{-13} \text{ J}$$

$$200 \text{ MeV} = 200 \times 1.602 \times 10^{-13} \text{ J}$$

$$= 32.04 \times 10^{-12} \text{ J}$$

$$= 32.04 \times 10^{-12} \text{ W·s}$$

$$\therefore \quad \text{Number of fission/s for 1 W} = \frac{1}{32.04 \times 10^{-12}}$$

$$= 3.12 \times 10^{10}$$

That means,

$$1 \text{ W} = 3.12 \times 10^{10} \text{ fission/s.}$$

(ii) $1 \text{ kW} = 3.12 \times 10^{10} \times 1000$ fission/s

$= 3.12 \times 10^{13}$ fission/s

(iii) $1 \text{ MW} = 3.12 \times 10^{10} \times 10^{6}$ fission/s

$= 3.12 \times 10^{16}$ fission/s

PROBLEM 6.2 Calculate the power generated per day by fissioning

(i) 1 g of U^{235}; (ii) 1 kg of U^{235}

Solution:

(i) From Problem 6.1, we know that

Number of fission/s for 1 W $= 3.12 \times 10^{10}$

Number of fission per day for 1 W $= 3.12 \times 10^{10} \times 24 \times 3600$

$$= 2.7 \times 10^{15}$$

Hence, number of atoms required for 1 W for a day $= 2.7 \times 10^{15}$

$$\text{Number of atoms in 1 g of } U^{235} = \frac{6.02 \times 10^{23}}{235} = 2.56 \times 10^{21}$$

[Avogadros number $= 6.02 \times 10^{23}$]

$$\text{Power generated} = \frac{2.56 \times 10^{21}}{2.7 \times 10^{15}} = 0.95 \times 10^{6} \text{ W}$$

$$\simeq 1 \text{ MW}$$

That means, 1 g of U^{235} can produce approximately 1 MW power for a day.

(ii) Accordingly 1 kg of U^{235} can produce approximately 1000 MW (= 1 × 1000) of power for a day.

Note: One mole of any atomic species contains the Avogadros number of individual atoms (or nuclei).

PROBLEM 6.3 Calculate the energy released by the fission of 1 kg of U^{235}.

Solution:

Method 1: With reference to Problem 6.2, we know that 1 kg of U^{235} can generate 1000 MW of power for a day.

$$\therefore \quad \text{Energy released} \simeq (1000 \times 10^{3} \text{ kW}) \times 24 \text{ hours}$$

$$\simeq 24 \times 10^{6} \text{ kWh}$$

Method 2: 1 g of U^{235} contains 6.02×10^{23} atoms

Fissioning of one atom releases 200 MeV

∴ The energy released in fissioning of 1 kg of

$$U^{235} = \frac{1000 \text{ g}}{235 \text{ (atomic mass)}} \times 6.02 \times 10^{23} \times 200 \text{ MeV}$$

$$= 51 \times 10^{25} \text{ MeV}$$

$$= 51 \times 10^{25} \times 1.602 \times 10^{-13} \text{ J or W·s}$$

$$= 81.7 \times 10^{12} \text{ W·s}$$

$$= \frac{81.7}{1000} \times 10^{12} \times \frac{1}{3600} \text{ kWh} = 22.7 \text{ kWh}$$

$$\simeq 24 \times 10^{6} \text{ kWh}$$

PROBLEM 6.4 In a reactor the thermal neutron flux is 1.2×10^{16} n/m^2 s. The absorption cross-section of natural uranium is 36.18 m^{-1}. The fission cross-section of natural uranium is 20.30 m^{-1}.

(i) Determine the absorption rate in uranium

(ii) Determine the power density of the reactor

Solution: Before solving the problem let us know the fundamental definitions and equations related to the problem.

N = Number of atoms (or nuclei) per unit volume (m^3)

σ = Microscopic cross-section in m^2 per nucleus

Σ = Macroscopic cross-section in m^{-1} = $N\sigma$ m^{-1}.

If the target material is an element of atomic weight A on the conventional scale, 1 mole has a mass of 10^{-3} A kg and contains number of atoms (or nuclei) equal to Avogadro number N_A (i.e., 6.02×10^{23}). If the mass density of the element is kg/m^3, the number density is given by

$$N = \frac{\rho N_A}{A \times 10^{-3}} = \frac{\rho N_A}{A} \times 10^3 \text{ atoms/m}^3$$

$$\Sigma = \frac{\rho N_A}{A} \sigma \times 10^3 \text{ m}^{-1}$$

If n is the neutron density (number of neutrons/m^3) and v the neutron speed in m/sec, then the neutron flux 'Φ' can be equated as

$$\Phi = nv \text{ neutrons/m}^2\text{s}$$

Rate of neutron interaction = Σnv interactions/m^{3}s

$$= \Sigma\phi \text{ interactions/m}^2\text{s} \quad (1)$$

Alternatively,

Let λ be the mean free path (the average value of the distance the neutron travels before undergoing the reaction).

Average number of reactions per second = v/λ for a neutron. For a beam containing n neutrons/m^3, the number of interactions/m^{3}s, is thus, nv/λ interactions/s

In other words,

$$\text{Rate of interaction} = nv/\lambda \text{ interactions/m}^3\text{s} \quad (2)$$

From Eqs. (1) and (2), we get

$$\lambda = \frac{1}{\Sigma} \text{ m}$$

That means, the neutron mean free path for a specified reaction is the reciprocal of the macroscopic cross-section for that reaction.

Coming back to the problem,

(i) Rate of absorption = Rate of neutron interaction

$$= \Sigma\phi$$
$$= 36.18 \text{ m}^{-1} \times 1.2 \times 10^{16} \text{ n/m}^2\text{s}$$
$$= 43.42 \times 10^{16} \text{ interactions/m}^3\text{s}$$

(ii) Fission rate = $\phi \times$ Fission cross-section

$$= 1.2 \times 10^{16} \times 20.3 = 24.36 \times 10^6 \text{ fissions/m}^3\text{s}$$

1 W power = 3.12×10^{10} fission/s [Refer Problem 6.1]

$$\therefore \quad \text{Power density} = \frac{24.36 \times 10^6}{3.12 \times 10^{10}} \text{ fissions/m}^3\text{s}$$

$$= 7.81 \times 10^6 \text{ W/m}^3 = 7.81 \text{ MW/m}^3$$

Power density = 7810 kW/m^3

PROBLEM 6.5 Calculate the density of U^{238} nuclear matter.

Solution: The radius of any nucleus = $1.57 \times 10^{-15} \times \sqrt[3]{A}$ m

where, A = The number of nucleons in nucleus

Radius of uranium nucleus = $1.57 \times 10^{-15} \times \sqrt[3]{238}$

$= 1.57 \times 10^{-15} \times 6.2$

$= 9.73 \times 10^{-15}$ m

Volume of uranium nucleus = 3.856×10^{-42} m^3 [$= \pi/6(2r)^3$]

$= 3.856 \times 10^{-42}$ m^3

Mass of uranium nucleus = $238 \times 1.66 \times 10^{-27}$ kg

[1 atomic mass unit (amu) = 1.66×10^{-27} kg]

$= 395 \times 10^{-27}$ kg

$\therefore$ The density of U^{238} nuclear matter = $\dfrac{395 \times 10^{-27}}{3.856 \times 10^{-42}}$ kg/m^3

$= 1.024 \times 10^{17}$ kg/m^3.

PROBLEM 6.6 Define atomic mass unit (amu) and find out the equivalent mass in kg of an amu. Also, find out the masses of a proton, a neutron and an electron.

Solution: Masses of individual atoms are expressed in terms of the atomic mass unit (amu) which is exactly one-twelfth of the mass of the carbon (C) atom.

Equivalent of amu in kg:

The mass of a single carbon atom = $\dfrac{12 \times 10^{-3}}{\text{Avogadro number}}$ kg

$= \dfrac{12 \times 10^{-3}}{6.02 \times 10^{23}}$

1 amu = $\dfrac{1}{12}$ of the mass of a carbon atom

$= \dfrac{12 \times 10^{-3}}{12 \times 6.02 \times 10^{23}} = 1.66 \times 10^{-27}$ kg

Masses of a proton, a neutron and an electron:

Mass of a proton = 1.007276 amu

$= 1.007276 \times 1.66 \times 10^{-27}$ kg

$= 1.672 \times 10^{-27}$ kg

$$\text{Mass of a neutron} = 1.008665 \text{ amu}$$
$$= 1.008665 \times 1.66 \times 10^{-27} \text{ kg}$$
$$= 1.674 \times 10^{-27} \text{ kg}$$
$$\text{Mass of an electron} = 0.000549 \text{ amu}$$
$$= 0.000549 \times 1.66 \times 10^{-27} \text{ kg}$$
$$= 9.11 \times 10^{-31} \text{ kg}$$

PROBLEM 6.7 If a Nuclear Power Plant has to produce 1000 MW power, how much slightly enriched fuel (3% Uranium-235) of U^{238} is required to be loaded initially if the thermal efficiency of the NPP is 20%? The reactor is expected to operate continuously for 300 days an year before it is being refuelled.

Solutions: Electrical power output = 1000 MW

Thermal efficiency = 20%

$$\text{Thermal power output required from the reactor} = \frac{1000}{0.2} = 5000 \text{ MW}$$

1 kg of U^{235} fuel is capable of producing 1000 MW of thermal power for a day (Refer Problem 6.2)

The equivalent amount of slightly enriched U^{238} fuel (i.e., with 3% U^{235} in it) = $\frac{1}{0.03}$ = 33.3 kg.

$$\therefore \quad \text{Minimum fuel requirement for 300 days} = \frac{5000 \text{ MW}}{1000 \text{ MW}} \times 33.3 \times 300$$
$$= 49{,}950 \text{ kg}$$
$$\cong 50 \text{ T}$$

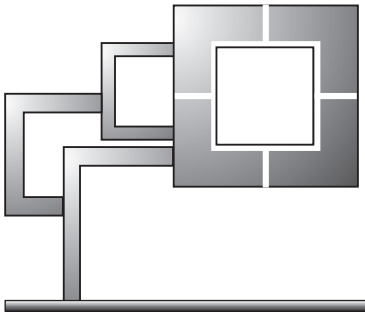
To take care of the loss of fuel during the operation initial loading is generally done to the tune of 150 to 200% of the calculated value.

Hence, 75 T to 100 T fuel has to be loaded initially to have trouble-free operation of the plant.

EXERCISES

1. What is called fissile material? Give an example.
2. What is called fertile material? Give an example.
3. What is the percentage of uranium-235 (fissile material) present in naturally occurring Uranium-238 (fertile material)?
4. Calculate the average thermal neutron flux in a reactor when the power density is 10,000 kW/m^3. The fission cross-section is 20.30 m^{-1}. (Assume 1 W = 3.12×10^{10} fission/s).
5. How do you classify the nuclear reactors?

6. What are the important components of a thermal nuclear reactor?
7. In what respect sodium cooled graphite moderator reactor is superior to other type of thermal reactors? Give the details of liquid metal (Na) cooled reactor power plant. What is the advantage of secondary cooling system?
8. What are the general characteristics of fast breeder reactor?
9. Give the basic principles of reactor control. Explain the methods of control employed to meet the thermal power requirement to match electrical power requirement in a Nuclear Power Plant.
10. Name the important radiation detectors used for measuring the reactivity.
11. Describe the working principle of a compensated ionization chamber with sketch.
12. Describe the means of detecting the neutron flux and density.
13. Discuss the problem of health hazard from nuclear radiation. Briefly enumerate different instruments used in Nuclear Power Plant to measure radioactive dose.
14. What are the important considerations in the site selection of a Nuclear Power Plant?
15. A reactor produces heat at the rate of 5000 MW. How many atoms of uranium-235 undergo fission per second? If the fuel in the core contains 3000 kg of uranium-235, what fraction of the fissile material will be used for 30 days of operation?
16. What is called critical mass?
17. What is called multiplication factor? Relate it with sub-critical, critical and super critical states of the system.
18. What are the important components of Instrumentation and Control system in a NPP?
19. Indicate approximately the behaviour of ion-pairs in an electric field in a graph
20. What are the types of ionization chambers used for measuring neutron flux?
21. What are the functions of control rods in a reactor?
22. What are the different methods of control possible in a reactor?
23. Explain with sketch the reactor thermal energy control using cascade control. [Coolant flow loop can be master and the neutron flux loop as slave loop].
24. What are the main differences in the control strategy adopted for BWR and PWR?
25. Explain the role of reactor control system during start-up and shut down of the reactor.
26. Explain how distributed control system can be gainfully employed for controlling NPP.
27. What is meant by surveillance, diagnostics and prognostics applied to NPP? Why is it very important?
28. Why radiation protection and monitoring plays a vital role in NPP?
29. Give an account of units used for radiation measurement.
30. What are the permissible limits of accumulated absorbed dose for human beings? Express them in different units.



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